COMBUSTION

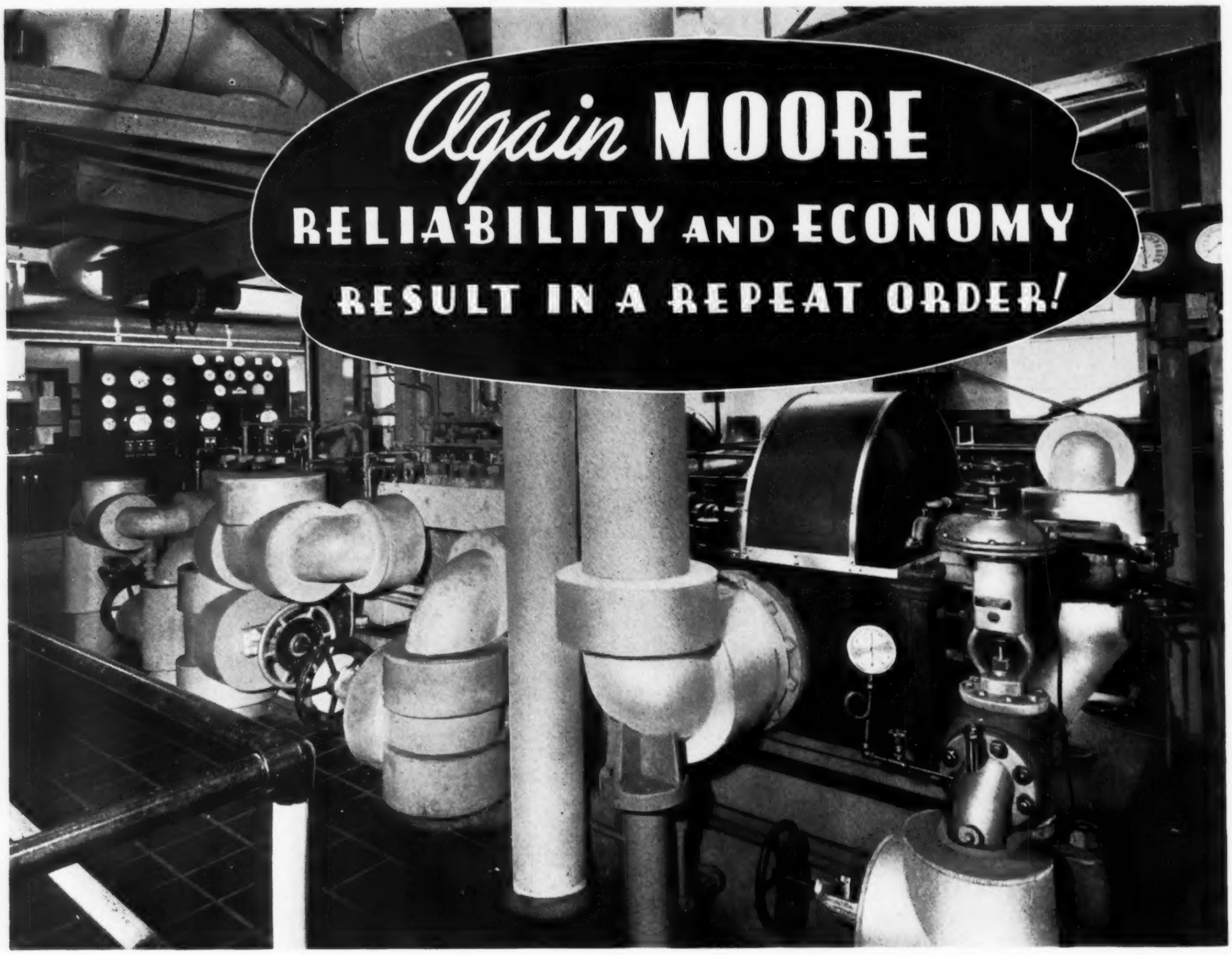
DEVOTED TO THE ADVANCEMENT OF STEAM PLANT DESIGN AND OPERATION

Vol. 8, No. 3 SEPTEMBER, 1936 25c a copy

Looking into the furnace of the 900,000 lb per hr, 1400-lb pressure boiler unit which recently went into service at the Rouge Plant of the Ford Motor Co.

"Topping" Extension to Omaha Steam Plant

Load Distribution for Best Overall Economy



THIS 450 HP Single Stage Moore Turbine is installed in No. 3 plant of the Rochester Gas & Electric Corp., at Rochester, N. Y. It drives a boiler feed pump and for the present operates on steam at 210# gauge, 525° total temperature at the throttle, and exhausts against 5# gauge back pressure. The design of the turbine is such that it may be operated at a future date on higher pressure steam with 750° total temperature.

The entirely satisfactory performance of this turbine since its installation resulted in a repeat order for a duplicate turbine for another Rochester Gas and Electric Corporation plant.

Where conditions require a thoroughly reliable and dependable drive for such service as boiler feeding a Moore Single Stage Turbine will assure you of years of trouble free operation.

MOORE STEAM TURBINE CORPORATION, WELLSVILLE, N. Y.

MOORE STEAM TURBINES

COMBUSTION

DEVOTED TO THE ADVANCEMENT OF STEAM PLANT DESIGN AND OPERATION

VOLUME EIGHT NUMBER THREE

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FOR SEPTEMBER 1936

FEATURE ARTICLES

EDITORIALS

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EDITORIAL

Net or Gross Efficiency

In the July issue of COMBUSTION figures were quoted from the report of the Electricity Commissioners showing the performance of leading British power stations. As was to be expected, a number of readers compared these figures with the performance of American power stations of similar size and operating at comparable load factors, and several letters were received inquiring as to whether the thermal efficiencies reported were based on gross or net station output. Nowhere in the report was this indicated. In line with usual British practice, it was suspected that the figures were based on units generated without allowance for power used by the auxiliaries and subsequent inquiry abroad has verified this assumption.

American practice, in general, is to report net efficiencies; hence in order to make any direct comparisons with the British stations it becomes necessary to know the auxiliary power in each case. Aside from such comparison of stations here and abroad, the reporting of gross efficiencies gives in some cases an incorrect representation of the relative performance of the British power stations listed, because of the wide differences in the auxiliary power requirements of some of these stations. For this reason the practice has long been a bone of contention in England.

International standards have accomplished much in minimizing confusion in engineering practice. Here is another that might well be approached by the properly constituted bodies.

The World Power Conference

As this issue goes to press the World Power Conference is in full swing with an attendance from abroad of about seven hundred, augmented by a considerable number of American engineers. The work and plans of a large staff and numerous committees, involving over six hundred individuals for many weeks, is now under test and it is hoped that the results will have rendered the efforts worth while.

The sessions at Washington served to emphasize the important rôle that power plays in the present social structures of most nations. They stressed the fact that technical developments in the production of power have advanced far beyond the economic aspects of its distribution and utilization, and revealed how the various countries are dealing with the problem.

As for the technical program, it was unfortunate that the scheduled arrivals and departures of delegates necessitated a duplication of the technical tours, plant visits and round table conferences thus involving both pre-conference and post-conference programs. This imposed an added burden on local committees. While the number taking in the pre-conference tours was considerably less than had been anticipated, which detracted from the attendance at round-table discussions and made necessary certain departures from the set program, the experience gained should prove helpful in handling the post-conference program with its larger enrollment.

Had the World Power Conference been held a year from now, there would have been more to show the visitors from abroad. Coming, as it has, in the wake of five depression years during which there was little power plant activity, it finds the new steam power developments in this country still mostly in the construction stage. Hence there is not much to report in the line of experience and performance with advanced practice as embodied in these new installations. The situation is similar to that which existed two or three years earlier in both Germany and England in which countries, however, many new installations are now operating.

Despite this situation, the Conference has afforded an opportunity for the exchange of ideas, both technical and economic, for making personal contacts and for the visitors to see industrial America at work, the net results of which should fully compensate for the time spent.

Hydro Power Abroad

Two of the World Power Conference papers, which are briefly abstracted in this issue, reveal the governmental attitudes toward hydro power in both France and Germany. In the former much of the hydro power is subsidized through governmental loans at low or no interest and regulation has favored the loading of these plants at the expense of the steam stations with the result that the output from water power now exceeds that from steam.

In Germany the available water power is relatively small yet its full utilization is encouraged for, as is aptly stated by Dr. Menge and Dr. Schult, "Every cubic meter of water running to waste means a loss to national wealth."

These two instances reflect the present Continental attitude as to power generation linked with national policies. While striving for efficiency in power generation and utilization, conservation of national resources is paramount.

Despite what some would have us believe, and accepting the premise that conservation of national resources is sound in principle, the situation in this country has not yet reached the point where such conservation must take precedence over plain common-sense economics in the choice between steam and hydro power. Each has its place, but it is significant that practically all private construction now under way in the power field is confined to steam plants—a fact that reflects the judgment of American engineers in meeting the present demand for increased capacity.

This is no reflection on what is being done abroad but it must be remembered that conditions on the two sides of the Atlantic are not comparable.

"TOPPING" EXTENSION TO OMAHA STEAM PLANT

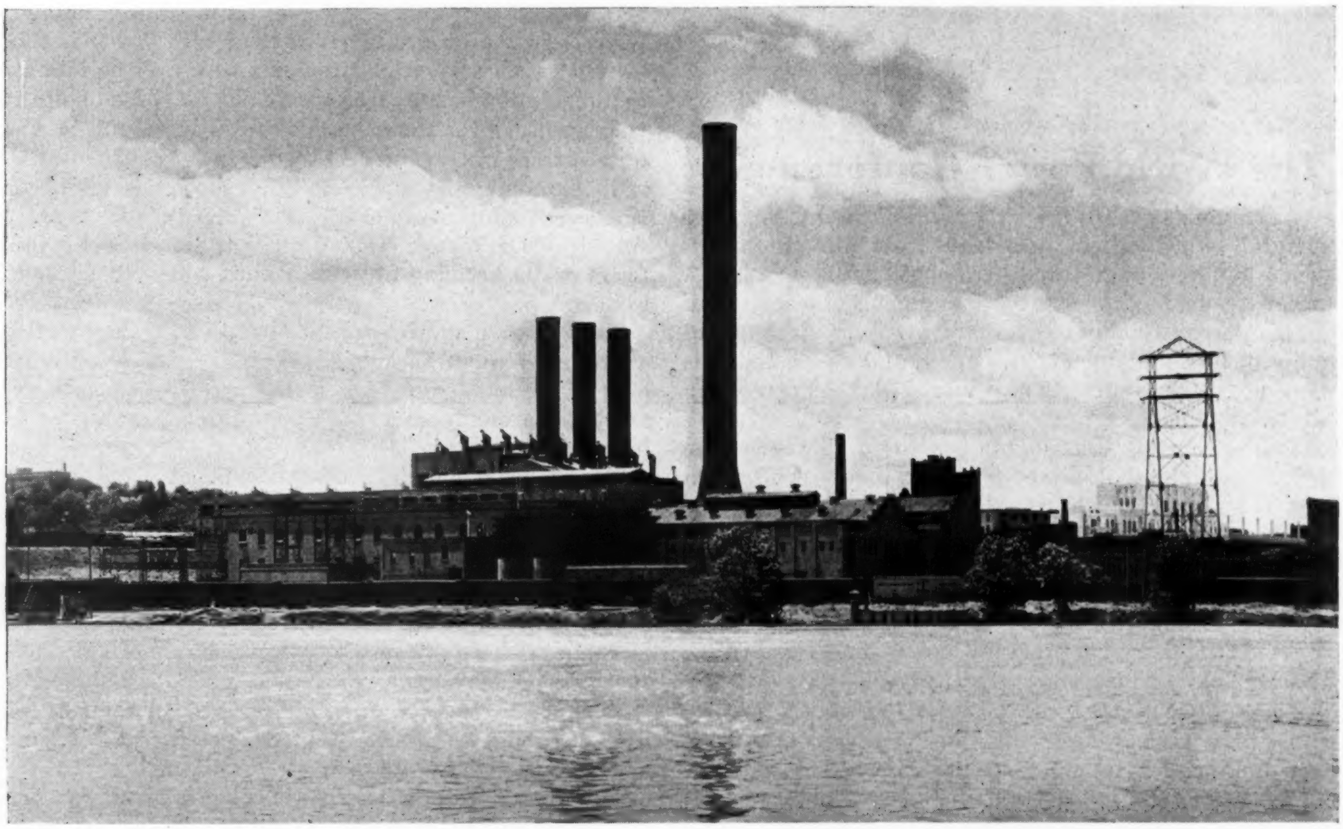
By LOUIS ELLIOTT
Consulting Mechanical Engineer,
Ebasco Services, Inc., New York

As illustrating a situation in which a relatively small 1200-lb 900 F superposed turbine has proved economic, description is given of a 12,000-kw extension to the Omaha steam plant of the Nebraska Power Company. The turbine will supply steam to an existing 200-lb 500 F 15,000-kw unit, giving a combined unit of approximately 27,000-kw capacity. The single boiler - economizer - air heater unit, equipped with a 570 sq ft traveling-grate stoker, is designed for a maximum of 275,000 lb of steam per hour.

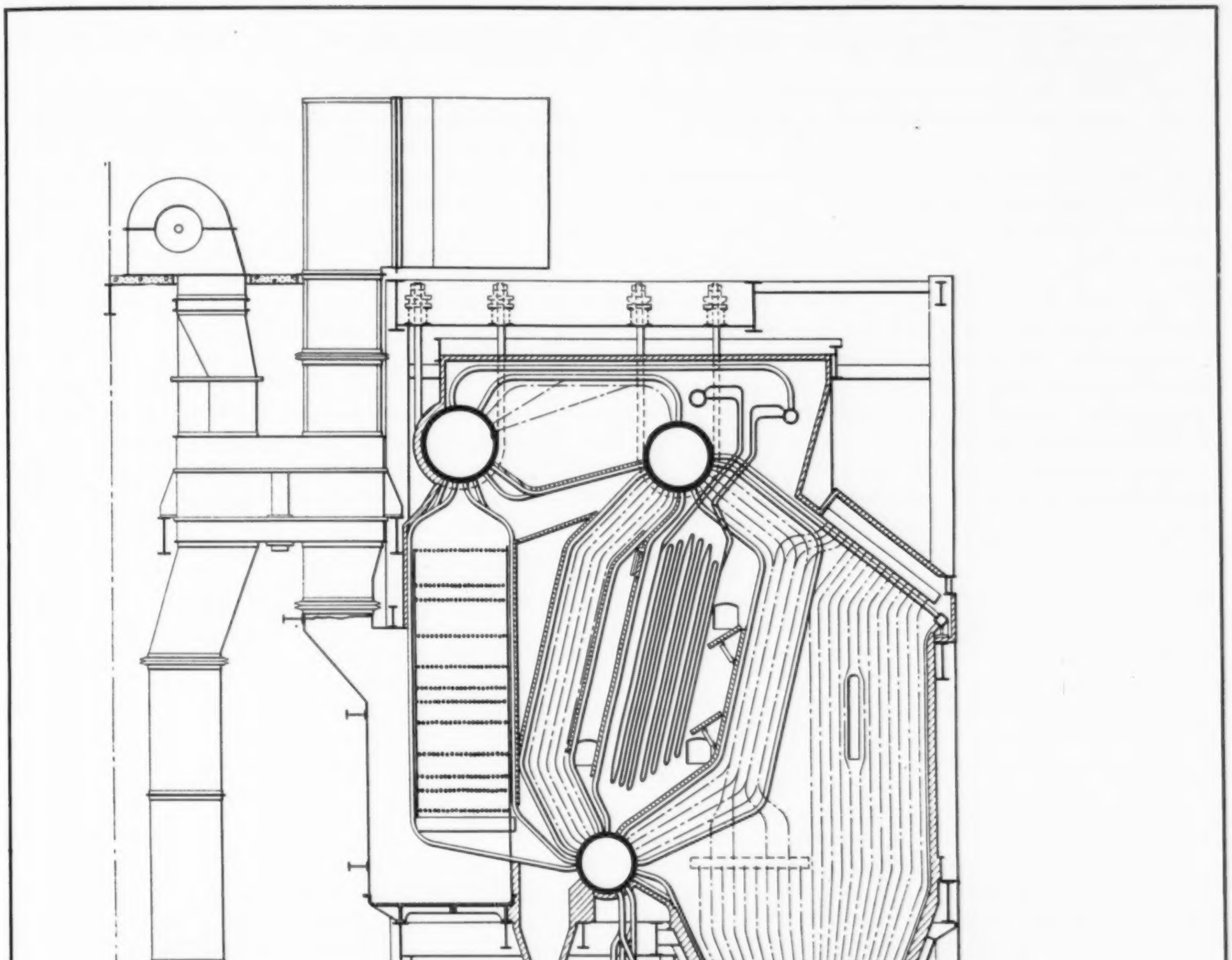
WITH the recent growth of power load, the Nebraska Power Company has found it necessary to provide additional capacity in its Omaha station. Because of certain special conditions it has seemed advisable to provide a relatively small power extension, rather than attempt to plan for a longer future. The existing Omaha plant contains one 25,000-kw, two 20,000-kw and one 15,000-kw turbine units, beside a number of smaller machines serving as reserve. Firm capacity is something over 70,000 kw, and peak loads have been of the same magnitude. The 15,000-kw turbine runs at 200-lb gage and 500 F total steam temperature, and the larger machines at 310 lb and 690 F. Plant economy has been approximating 16,000 Btu per kwhr net output.

An economic study was made, comparing a number of plant extensions, each one to add approximately 12,000 kw to the capacity, and each including one boiler with a traveling-grate stoker. All major existing boilers are stoker-fired, and the use of this method of firing for the additional unit was found advisable. The plans compared were as follows:

I—1200-lb 900 F turbine-generator superposed on existing 15,000-kw 200-lb unit;



Omaha Steam Plant of the Nebraska Power Company



Section through high-pressure boiler at Omaha Steam Plant

This 1200-lb, 900 F unit consists of a 255,000 lb per hr CE bent-tube boiler, Elesco superheater, fin-tube economizer and vertical shaft Ljungstrom air heater. It is fired by a single 570 sq ft CE chain-grate stoker burning Kansas coal of low ash-fusing temperature—*Editor*

II—1200-lb 900 F turbine-generator superposed on existing 310-lb units;
III—650-lb 830 F condensing turbine-generator;
IV—310-lb 700 F condensing turbine-generator.

In making the economic comparison, cost of operation of entire plant, over a term of years, was estimated, in each case fitting the new unit into the load duration curve in such a manner as to obtain the lowest total annual cost. Plan I was figured to give a thermal economy of approximately 13,500 Btu per kwhr net output, and Plan II 14,200, for output from the superposed unit and corresponding low-pressure capacity. Plans III and IV were figured at about 13,500 and 14,800 Btu per kwhr, respectively. Estimated investments ranged between $1,100,000 and $1,600,000.

Total computed energy costs for one year, based on 400,000,000 kwhr output, and including production costs and 12 per cent fixed charges on new money, were very nearly the same—within about two per cent—for the four plans of development. In the complete study corresponding charges were figured over an extended period, for each of the four schemes, in order to give a reasonable economic comparison over a considerable portion of the plant-extension life.

Comparing the two superposition schemes, Plan II was eliminated because of higher investment and slightly higher total energy costs than Plan I. The comparison between Plans III and IV, for condensing turbines, was relatively close. A disadvantage of Plan III was that it would introduce a third steam pressure in the station.

Plan I, calling for a unit superposed on 200 lb, showed excellent fuel economy, and was adopted, in spite of its requiring a somewhat greater investment than either of the condensing-turbine extensions. Plan I avoids the use of certain space and facilities of special value for a future large extension, and makes it unnecessary to decide on the character of such extension.

Many comparative studies of this kind show approximately the same financial results for the various plans studied, and the decision, as here, must be based in large measure upon considerations other than that of total figured energy costs.

In the case of the Omaha station no superposed or other extension was warranted from considerations of economy alone; additional capacity had to be required, as was needed in this instance.

Description of Extension, Plan I

There is but one good-sized reasonably modern 200-lb turbine in the plant—rated at 15,000 kw, and it is upon this machine that the new back-pressure unit is to be superposed. Steam conditions of 1200 lb and 900 F give a reasonable approximation to the steam temperature desired at the 200-lb exhaust outlet of the superposed machine.

As this 15,000-kw unit has seen considerable service, it was dismantled and gone over with extreme care before decision was made to extend its life by using it in connection with a "topping" turbine. Although certain wear and minor defects were discovered, the judgment was that the machine was generally in sound condition, and capable of reliable operation for a considerable additional period. High capacity factor is a necessity in justifying a high-pressure, high-temperature extension of this kind.

It was originally intended to utilize existing low-pressure heaters and feed pumps, in connection with the new extension, the new feed pumps to take suction at an intermediate pressure. Such new pumps would then have had to handle feedwater at 380 F, heated by steam from the crossover between the high- and low-pressure turbines. As feedwater at this temperature might introduce difficulties in feed-pump operation and maintenance, it was decided to provide new pumps taking suction at low pressure and relatively low temperature, and to design the cross-over heater for the boiler pressure on the water side. These pumps—one active and one spare—will be driven by turbines, taking steam at 200 lb, so as to increase the output of the superposed machine. It was not found practicable, under existing heat-balance conditions, to use steam drive for other auxiliaries, such as draft fans.

The new turbine-generator is rated 10,000 kw at 80 per cent power factor and can carry 12,500 kw at unity power factor. The speed is 3600 rpm. It will exhaust into the 200-lb main, which normally will supply steam to the 15,000-kw unit; in case this unit is down, the steam will pass to the older 200-lb units. A reducing and desuperheating station will be provided, so that the new high-pressure boiler will be able to supply steam to the lower-pressure units in case the high-pressure turbine is down.

Large Chain-Grate Stoker Employed

The single new boiler unit includes a three-drum bent tube boiler, with a water-wall furnace, fired by a traveling-grate stoker having 570 sq ft effective grate surface. An economizer and an airheater form part of boiler unit, the guaranteed efficiency being 86 per cent at an output of 255,000 lb of steam per hr, when burning 12,000-Btu Kansas coal and taking feedwater at 380 F. The induced-draft fans will discharge into an existing concrete chimney.

The coal has a low fusing temperature of ash—about 2000 F—and quite troublesome slagging characteristics. For this reason, precautions were taken in laying out the boiler, as well as the superheater and economizer, to provide generous spacings between the tubes, and complete opportunity for lancing. A cross-section of boiler unit is here shown.

The boiler unit is notable as including a very large single stoker. Previous moderate-pressure boilers in this plant have employed twin stokers, with a firebrick wall between them. It is now felt, however, that stoker operation is sufficiently reliable to permit obtaining the benefit of the greater simplicity of a single grate. The installation also differs from most of the superposed plants now going in, in that a stoker is used instead of powdered coal. The stoker was selected because of lower cost, with substantially as good efficiency, and because it was better suited to the particular plant and local conditions.

Ebasco Services Incorporated, with which the author is connected, has assisted the Nebraska Power Company in working out the plans for this high-pressure plant extension.

Power Resources and Practice in Germany

A digest of data and trends pertaining to German energy supply and power plant practice as contained in two papers presented at the Washington Meeting of the World Power Conference, one by Dr.-Ing. A. Menge and Dr.-Ing. H. Schult and the other by Dr.-Ing. K. Rissmueller.

A COMPREHENSIVE review of power resources, developments and trends in Germany was contained in two papers presented at the Washington meeting of the World Power Conference. One, entitled "Significant Trends in the Development and Utilization of Power Resources," by Dr.-Ing. A. Menge and Dr.-Ing. H. Schult dealt with developments in the utilization of coal, petroleum, gas and electricity, mainly from 1925 to 1935 and contains much statistical data concerning Germany's power resources and production. The other, by Dr.-Ing. K. Rissmueller, dealt with "Technical Developments as a Factor of Economic Efficiency and Reliability of Electric Power Supply."

In the first paper it is shown that following the World War German power economy reached a low point, but from 1925 onward a revival set in and reached a high point in 1929. Then the economic depression brought about a set-back during which only the petroleum industry showed increased production. However, power production figures, with the exception of the economy of coal utilization, have now passed those of 1929.

Available Power Resources

The proved reserves of pit coal up to 2000 meters depth amount to 80,000 million tons although the probable reserves may reach 280,000 million tons. In 1935, 143 million tons of such coal were mined. Reserves of brown coal are estimated at 57,000 million tons and peat reserves 10,000 million tons. Since 1928 the production of brown coal has been greater than that of pit coal but the latter has been steadily increasing and is likely again to pass that of brown coal.

Petroleum occurs in Germany to a limited extent, the 1935 production amounting to 430,000 tons, or about five times that of 1925. From the same areas some natural gas is obtained.

The southern part of the country has relatively large water-power resources with considerable head, the total water power that could be developed being estimated at 3.7 million kilowatts. About one-third of this has already been developed.

With practically the whole of Germany covered by a high-tension grid system of interconnection, to which nearly every central station is connected, it has been recognized that it is more economical to transmit only the base load and to handle peak loads by the smaller local stations. Despite the fact that only under particularly favorable conditions can the cost of hydro power compete with that produced in a modern steam station, the development of water power has been encouraged, for every cubic meter of water running to waste means a loss to national wealth.

Several large diesel-engine peak-load plants have been built and energy storage has been provided for both water power and steam plants. An exceedingly large pump-fed storage plant that can meet a peak demand of 140,000 kw for several hours has been built near Herdecke and the Charlottenburg central station has a large steam storage installation with a capacity of 70,000 kwhr.

However, a division of the total production according to power source shows that solid fuels are the mainstay of the German electricity supply. Of the electric energy generated in 1934, 77.45 per cent were produced by solid fuels, of which 35.5 per cent were produced by pit coal and 41.5 per cent by brown coal and only 15 per cent by water power. This is shown graphically in Fig. 1.

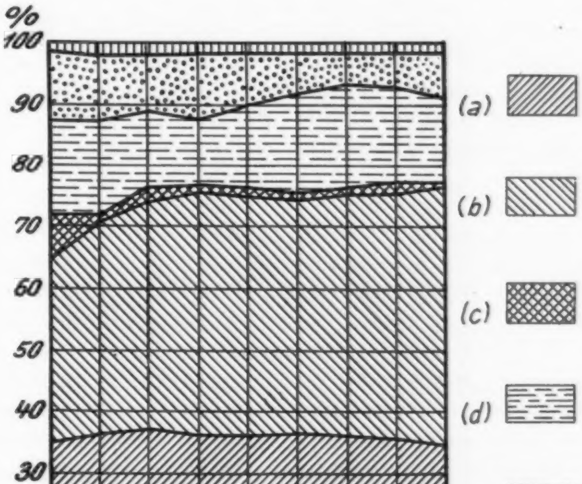


Fig. 1—Distribution of total German production of electric energy by sources

a. pitcoal; *b.* brown coal and lignite; *c.* mixture of solid fuels; *d.* water power; *e.* gas; *f.* other sources

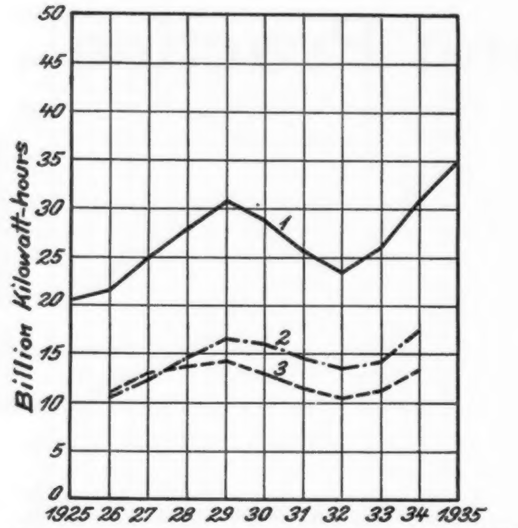


Fig. 2—German electricity production, 1925 to 1935

1. Total production; 2. By publicly owned plants; 3. By private plants

The following tabulation shows the total production in kilowatt-hours per capita from 1925 to 1935.

1925	325
1929	475
1932	360
1935	530

With reference to ownership of central stations only 13.2 per cent are entirely privately owned, 53.4 per cent are owned by municipalities and 34.4 per cent are owned by companies of mixed economic character.

The capacity of prime movers in central stations (public and private) increased from 1925 to 1934 from 8.7 to 13.4 million kilowatts, or 53 per cent, the annual production during the same period having risen from 20 to 30 billion kilowatt-hours. Thus, capacity and production increased at about the same rate when the whole period is considered. However, as will be seen by reference to Fig. 2, the capacity steadily increased up to 1930 and then remained practically stationary while the production had reached its highest level in 1929. The lowest level of production occurred in 1932 and in 1935 the 1929 figure was surpassed by 14 per cent.

Technical Advances

Reverting to the previously mentioned paper by Dr. Rissmueller, the author reviews the technical advances in Germany from 1918 to 1936.

Formerly, the upward trend in the consumption of electric power, which was only interrupted by the years of the depression, had led to the erection of power plants of the standard type, which had to take care of any load. Later, there was a pronounced tendency toward specialized plants, such as base-load plants, peak-load plants and standby plants. Such specialization also affected the location of the plant, in that the base-load plants were erected at points of cheapest generation and the peak-load plants at the centers of greatest consumption. In order to attain the cheapest and most reliable generation of electric power, improvement of the thermal process and of the designs in question was called for. The former development is characterized by:

1. The multi-stage heating of the feedwater by means of non-controlled extraction from the main turbine.

2. Increase of the pressure and temperature of the steam, the limitation of which, according to the present state of engineering, can be characterized by the critical pressure and a temperature of 500 C. In the case of the erection of power plants and extensions of plants not coupled with existing turbines, superheating was dispensed with for a time. The pressure was limited so that, with the temperature limit governed by the qualities of construction material, a permissible moisture content in the last turbine stages was still insured. The actual pressure limit is 45 to 60 atm and about 470 C at the throttle, depending on the cooling by fresh water or a cooling tower.

3. Introduction of reheating, which is made use of only if low-pressure turbines of the condensing type in good condition are to be operated in conjunction with back-pressure turbines. In order to attain a total steam temperature of about 350 C, corresponding to the existing plant, with condensing live steam and in order to increase the output of the back-pressure turbine as far as possible, an initial steam pressure of 130 atm at about 470 C is required.

Development in boiler design is marked by increased output per unit with special reference to large overload rating, adaptability, increase of efficiency and flattening of the efficiency curve over a wide range of loads. The output per unit depends mainly on the fuel used. The improvement in mechanical stokers, which became imperative in view of pulverized-coal firing, permitted the attainment of a boiler output of only about 100,000 lb of steam per hour. Because power plant construction required larger units, the development necessarily reverted to the use of pulverized coal despite the outstanding improvements made in stokers.

Having passed from the central pulverizing plant to the unit mill, the evolution of the Krämer mill was much in the line with this tendency of development. It originated in the lignite power plant, better to overcome the non-uniformity of the fuel, which affected stokers unfavorably, and thus making the performance of the lignite-fired boiler approach closely that of the black-coal-fired boiler. Latest developments prove that the Krämer mill can also be used for black coal; hence the problem of firing inferior fuel, while not completely solved, is at least simplified.

While stoker-fired furnaces limit the degree of air heating, the pulverized-coal furnace permits air heating up to the limit imposed by the materials of construction. The air heater permits an increase of efficiency over a wide range of load.

The endeavors of power plant designers to utilize higher pressures has led to special constructions apart from the further development of the drum-type boiler.

There are no objections to the drum-type boiler up to a pressure of about 60 atm, as long as the design insures the generation of dry steam. The introduction of the steam economizer leaves only the high-temperature heating surface for free circulation and is leading steadily to forced circulation. Increase of output is attained by utilizing the radiation in the furnace rather than the built-in heating surface. To what extent special designs will be able to gain ground in the field of medium pressures will depend largely on the cost of manufacture.

Whereas in the range of low pressures the overload capacity was insured by the drum, the capacity is re-

duced with increase in pressure; but this is balanced by the improved flexibility of the furnace, so that, at present, the pressure-drop accumulator is required only for considerable and suddenly occurring increases of output. In large city networks, however, the accumulator is even today of value.

The advances made in German steam-turbine construction during the last few years clearly reflect the endeavors to reduce initial and operating costs, and, at the same time, to improve reliability. This led to the construction of the largest single-shaft steam turbine made so far to operate at 3000 rpm for an output of 60,000 kw (80,000 kva). But, in general, for public utility power plants machines with outputs of 20,000 to 50,000 kw at 3000 rpm are employed. This is justified in so far as still larger units do not show any appreciable difference in price and steam consumption.

Turbines are now being built within this range of output with one or more casings in the well-known axial construction, and also as "counter-rotating" turbines of Ljungstrom design. Ljungstrom turbines have been built in Germany up to 40,000 kw at 3000 rpm, in one instance, and 50,000 kw at 1500 rpm, in another.

In the development of modern turbine construction special attention must be paid to packing of the individual stages and the glands. This problem is easy to solve with large mass flow, but becomes more difficult with small mass flow and higher pressures. Owing to the small specific volume of high-pressure steam, the blades in the high-pressure section must be of sufficient length; otherwise efficiencies will suffer and the gland losses are likely to be considerable. High steam temperature requires careful selection of materials. Alloyed steel or alloyed cast steel is used for the casings and the rotors. These alloys are composed principally of molybdenum, chromium and nickel.

The development of high-pressure turbines is showing further progress. While the increase of pressure did not offer any serious construction difficulties, the high superheat did. In general, it must be borne in mind that the parts operating within the high-pressure range should have as small rotating masses as possible, to permit considerable temperature drop.

Opinions still differ with respect to the use of house turbines. The increased reliability of the interconnected systems operates against them, while use of their exhaust steam for feedwater heating is in their favor.

Much more exacting demands are being made with regard to the construction of pipe lines and apparatus. Welding is replacing flanges to a growing extent, the latter being still used only in cases where frequent removal of parts appears necessary.

There is a divergence of views regarding the best method of treating makeup water. While there are no objections to chemical treatment of makeup water in the case of low pressures, evaporator plants are preferred in high-pressure installations.

Taken as a whole, the development of steam technique, the main factor in public utility generation of electric power, has not remained stagnant in Germany. Exaggerations have been avoided with regard to unit sizes and heat utilization, but, on the other hand, the way has been paved for developments along such lines as permit bringing the economical gain of the simple steam process close to the physically attainable limits.

Sodium Sulphite for Removal of Oxygen

(From the report on "Power Station Chemistry" of the Prime Movers Committee, E. E. I.)

The present general use of sodium sulphite as an auxiliary water treating reagent for the removal of residual dissolved oxygen has been attended with questions as to its stability. The fact that this salt, under certain conditions, is capable of dissociating in such a manner as to liberate an acid radical, has caused some operators to fear such dissociation may occur under boiler operating conditions, and in so doing, create an acidic condition in the steam and condensate. This condition, did it actually occur, would cause severe corrosion in steam lines, turbines and condensing equipment.

In order to dispel the fear in this regard, the Subcommittee has assembled data from operating experience and augmented this with sound theoretical advice to show that such dissociation of sodium sulphite does not take place in normal operating boilers. Should the salt become deposited as such in dry hot tubes, this type of dissociation may occur, and if the liberated acid is not redissolved in boiler water where it will become neutralized, it will be carried over with the steam. Operation which would permit this to occur is distinctly abnormal, and other reasons than the dissociation of sodium sulphite dictate the necessity for immediate corrective measures.

The experience of thirteen member companies is covered together with discussions of likelihood of decomposition, commercial forms available, methods of application and the theory of the action of the material.

Conclusions

Sodium sulphite has been found useful as a reagent for removal of the last traces of oxygen from boiler waters. The theoretical study of its use in alkaline solutions of boiler water concentration indicates no harmful effects. The operating experience of twelve member companies substantially confirms the theory.

One case of suspected decomposition of sodium sulphite with resulting corrosion was reported. There was, however, no direct evidence of breakdown of the sodium sulphite, and in the opinion of the Subcommittee the evidence can be attributed to other possible causes.

Pressures, temperatures, size and type of boilers, type of feedwater and methods of adding the material appear to have little influence on its effectiveness.

The anhydrous technical grade appears to be the simplest and most economical form to use. All members reporting were at that time using "Santosite," a commercial sodium sulphite compound.

Glen J. Christner, formerly in charge of The Eagle-Picher Lead Company's New York Insulation Division, was recently transferred to Cincinnati as manager of the entire Insulation Division.

Mr. Christner was graduated from The Missouri School of Mines in 1922. He was then associated with The American Bridge Company in Philadelphia until he joined The Ingersoll-Rand organization prior to joining The Eagle-Picher Lead Co.

SOME W. P. C. DELEGATES ON TOUR III

Prominent visitors from abroad inspect the Westinghouse Works

Front row, left to right—R. E. Helmand, Chief Engineer Westinghouse Electric & Manufacturing; Westinghouse engineer; Dr. A. Menge, Pres., Elektro-Werke A. F., Berlin; Dipl. Ing. Hermann Bussman, Dir. Betriebsverwaltung Elektrizitatswerke A.-G., Essen-Ruhr; Westinghouse Engineer; Dr.-Ing. Erich Rolf, Siemens-Schuckert-Werke A. F.; B. L. Kallir, Dir. A. E. G. Union Elektrizitats-Gesellschaft, Vienna; Mr. Crane, tour secretary (rear); Dr. Karl Hencky, Ch. Eng. I. G. Farbenindustrie.

(Right), Prof. L. de Verebely, Royal Hungarian Tech. Univ.

(Right), G. F. Lemaitre, V. P. de l'Union Financier pour l'Industrie Electrique, Paris

(Left to right), Dr. Hencky, Mr. Crane, B. L. Kallir, Dr. A. Menge and a G. E. Engineer

Atop the mercury unit at Schenectady

(Left to Right), A. Serruys, Belgium; G. F. Lemaitre, Paris; G. B. Roziers, Paris; B. L. Kallir, Vienna; Rudolf Vogel, Dusseldorf, Dr. Menge and H. Bussman

PERFORMANCE OF SOME AMERICAN POWER STATIONS FROM JANUARY 1. 1935 to DECEMBER 31, 1935

1	Name	River Rouge	Firestone (high-pressure)	Port Washington
2	Owner	Ford Motor Co.	Firestone Tire & Rubber Company	The Milwaukee, Elec. Railway and Light Co.
3	Location	Dearborn, Mich.	Akron, O.	Port Washington, Wis.
4	Operating press., lb per sq in. gage; operating temp, F	5 boilers, 250-650; 2 boilers, 1,250-750; 1 boiler,[c] 1,250-900	1,250-750	1,230-825
5	Total installed capacity, kw	325,000	10,000	80,000 (noml) 85,000 (max)
6	Unit capacity of turbines, kw, rpm	#1-2-3 30,000-1,200 #4 & 5 110,000-1,800 #6 15,000-3,600[d]	10,000-3600[d]	80,000-1800
7	Spinning reserve carried on system?	No	No	Yes
8	Type and size steam-reheater surface, sq ft	#4 turbine—2 steam reheaters 8,150 sq ft each	None	Radiant reheater, 1,420 sq ft on rear wall of furnace
9	No. extraction heaters	#4 & #5 turbines—4	None	5
10	Final temp feed, full load, F	407 on h-p plant 240 on l-p plant	375	427
11	Total no. boilers	8 (7 in operation)	One	One
12	Boiler surface per unit, sq ft	1 boiler, 250 lb: 26,470; 4 boilers, 250 lb: 29,494; 2 boilers, 1,250-750: 37,274; 1 boiler, 1,250-900: 39,500	17,680	44,087 exclusive of waterwalls
13	Economiser surface per boiler unit, sq ft	None; None; 14,000; 25,300	8,110	None
14	Air-preheater surface per boiler unit sq ft	None; 39,700; 64,800; 88,016	23,100	2—plate-type, total = 121,000
15	Max steam-generator output per boiler unit, lb per hr	200,000; 500,000; 750,000; 900,000	350,000	690,000
16	Average boiler-plant eff per unit, per cent	82.5; 83.7; 87.5	85	84.9 (5 months)
17	Furnace equipment	Pulverized coal, fin-type waterwalls; tangential firing on h-p units; dry bottom	Water-tube walls and bottom	Waterwalls, dry hopper bottom, low heat release
18	Ash-handling equipment	Ash-screw, vacuum system	Slag-tap bottom, A.S.H. hydrojet disposal	A.S.H. sluicing conveyor
19	Condenser surface per unit, sq ft	Turbines #1-2-3 48,000; #4 77,000; #5 73,000	None	52,500
20	Max cooling-water temp, F	78		75
21	Min cooling-water temp, F	32		35
22	Gross annual output, kwhr	l-p plant 136,229,971; h-p plant 492,288,000	51,342,000	185,515,000[e]
23	Auxiliary use, kwhr	7,210,000; 21,120,000	2,795,228	10,159,431[e]
24	Net annual output, kwhr	129,019,971; 471,168,000	48,546,772	175,355,569[e]
25	Auxiliary use, per cent	5.29; 4.29	5.45	5.48
26	Avg cost coal per ton (2,000 lb)		$2.80	$3.82
27	Heating value coal, Btu per lb	14,150	12,300	12,999
28	Average annual station performance (net output), Btu per kwhr	l-p plant, 16,570; h-p plant, 12,250	32,400[d]	11,166[e]
29	Annual load factor,[a] per cent	49.5	Base-load unit operates at capacity	61[e]
30	Annual use or capacity factor,[b] per cent	35.8	58.5	53[e]

1	Name	Riverside (450-lb section)	Hudson Ave				
2	Owner	Northern States Power Co.	Brooklyn Edison Co				
3	Location	Minneapolis, Minn	Brooklyn, N. Y				
4	Operating press., lb per sq in. gage; operating temp, F	417–738	400–730				
5	Total installed capacity, kw	35,000	770,000				
6	Unit capacity of turbines, kw, rpm	35,000-1,800	#1-2-3— 50,000-1,200 #4 — 80,000-1,800 #5-6 —110,000-1,800 #7-8 —165,000-1,800				
7	Spinning reserve carried on system?	Yes	Yes[f]				
8	Type and size steam-reheater surface, sq ft	None	None				
9	No. extraction heaters	3 on 35,000-kw unit and 1 in l-p (225-lb) section	2 per unit except #4 which has 4				
10	Final temp feed, full load, F	303	#1-2-3—300; #4—380 #5-6-7-8—275				
11	Total no. boilers	3	32 (4 per turbine)				
12	Boiler surface per unit, sq ft	17,740 + 1,330 in waterwall	Turbines #1-2-3 12 boilers 19,650	Turbine #4 4 boilers 22,920	Turbine #5 4 boilers 23,760	Turbine #6 4 boilers 24,700	Turbines #7-8 8 boilers 24,450
13	Economiser surface per boiler unit, sq ft	12,096			14,960	21,420	22,400
14	Air-preheater surface per boiler unit, sq ft	None		43,290			
15	Max steam-generator output per boiler unit, lb per hr	750,000	145,000	235,000	312,000	312,000	452,000
16	Average boiler-plant eff per unit, per cent	83.89	m	m	86.8	87.3	86.7
17	Furnace equipment	Underfeed stoker, waterwalls	Refractory wall	Bare-tube water-wall	Block-covered water-wall	Block-covered water-wall	Fin-tube water-wall
18	Ash-handling equipment	A. S. H. ash-sluicing	Sluice only		Individual hoppers and sluice		
19	Condenser surface per unit, sq ft	29,000	70,000	80,000	85,000	88,500	101,000
20	Max cooling-water temp, F	88.5	31				
21	Min cooling-water temp, F	32	31				
22	Gross annual output, kwhr	192,077,000	2,057,548,000				
23	Auxiliary use, kwhr	5,020,000	83,910,000				
24	Net annual output, kwhr	187,057,000	1,973,638,000				
25	Auxiliary use, per cent	2.6	4.08				
26	Avg cost coal per ton (2,000 lb)		$4.862				
27	Heating value coal, Btu per lb	13,833	13,990				
28	Average annual station performance (net output), Btu per kwhr	13,526[f]	13,500				
29	Annual load factor,[a] per cent	69.7	46.9				
30	Annual use or capacity factor,[b] per cent	62.6	30.4				

NOTE: Pressures in lb per sq in. gage. Boiler efficiencies based on higher heating values of fuel. A.S.H. = Allen, Sherman, Hoff Company.

[a] *Annual load factor* = The ratio of the gross annual output in kwhr to the product of the maximum peak load of the year and the total hours of operation per year.

[b] *Annual use or capacity factor* = The ratio of the gross annual output in kwhr to the product of the rated capacities of the units in the station and the hours of the year (8760).

[c] Under construction.

[d] Noncondensing.

[e] This station had only been in operation for 6 months when data were compiled.

[f] The high-pressure equipment was superposed upon an older low-pressure plant

From a comprehensive review of American power plant practice as presented in a paper by Prof. A. G. Christie at the Niagara Falls Meeting of the American Society of Mechanical Engineers on September 17. The paper is printed in full in the September issue of *Mechanical Engineering*.

Northeast	Buzzard Point	Conner's Creek (rebuilt section)	Burlington	1
Kansas City Power & Light Co.	Potomac Electric Power Co.	Detroit Edison Co.	Public Service Elec. & Gas Co. of N. J.	2
Kansas City, Mo.	Washington, D. C.	Detroit, Mich.	Burlington, N. J.	3
l-p plant, 275-700 h-p plant,[f] 1,300-725	675-845	600-850	645-846 (h-p unit)[f]	4
139,000	35,000	90,000	60,000 kva	5
1—10,000-3,600 h-p unit[d] 3—23,000-1,800-275 lb 2—30,000-1,800-275 lb	35,000-1,800	3—30,000-1,800	1 h-p—22,500 kva-3,600[d] 3 l-p—12,500 kva-1,800	6
Yes	Yes	Yes	None	7
Each h-p boiler contains a 967 sq ft radiant reheater	None	None	None	8
2 on l-p turbines	3	4	3 and evaporator	9
215	350	388	366	10
2—1400 lb per sq in. 12— 300 lb per sq in.	two (one for future unit)	4	1—h-p boiler	11
8 boilers, 300 lb, 13,512; 2 boilers, 300 lb, 12,740; 2 boilers, 300 lb, 12,740; 2 boilers, 1,400 lb, 16,950	5,805	26,792	43,756	12
14,000 10,037 8,100 10,891	11,067	8,490	None	13
...... 9,600 9,600 39,270	45,994	28,980	41,800	14
125,000 125,000 125,000 250,000	375,000	420,000	600,000	15
80.6 (composite average all boilers) 85.4 on h-p boilers	84.1	87.5	84	16
h-p boilers with water-cooled furnaces and pulverized-coal fired; also 1 l-p boiler; l-p boilers, stoker-fired, chain-grate	Bailey stud-tubed refractory-covered slag bottom	Underfeed stokers, complete waterwalls	8 Enco oil burners, 8 Lopulco pulverized-coal burners	17
Water-sealed ashpits, grab bucket	Hydraulic sluicing, Cottrell precipitator	Conventional stoker ash hopper	A.S.H. hydrojet disposal	18
3—23,000 kw 35,000; 1—30,000 kw 40,000; 1—30,000 kw 45,000	30,000	27,000	h-p—noncondensing l-p—16,000 each	19
86	84 (monthly avg)	78	82	20
32	39 (monthly avg)	32	35	21
464,855,000	222,886,000	461,250,300[g]	305,615,000	22
29,456,579	11,740,900	19,983,000[g]	17,082,236	23
435,398,421	211,145,100	441,267,300[g]	288,532,764	24
6.33	5.27	4.33	5.59	25
$2.394	$4.51	$3.68[g]	$4.70 (oil—$0.80 per bbl)	26
10,349	14,193	13,350[g]	14,118 (Oil—18,164)	27
14,920	12,550	18,000[g]	15,257 (l-p section alone—29,559)	28
48.3	62.8	24.6[g]	62	29
38.7	72.6	Rebuilt section only ...... 69.4 Old l-p section ...... 2.5 Combined[g] 32.3	58	30

Charles Leavitt Edgar				C. R. Huntley No. 2[n]	Station A	1
The Edison Electric Illuminating Company of Boston				Buffalo General Electric Co.	Pacific Gas & Electric Co.	2
Fore River, North Weymouth, Mass.				Tonawanda, N. Y.	San Francisco, Calif.	3
3 boilers—365-715 1 boiler—1,150-700, reheat at 365-715 4 boilers—1,325-725, reheat at 365-750				425-750	1,250-750 750 reheat	4
Main generators—157,860 Auxiliary generators—9,000 Total turbines—166,860				160,000	100,000	5
2—38,000-1,800 for 350 lb per sq in., 700 F 1—65,000-1,800 for 350 lb per sq in., 750 F 1— 3,360-3,600 for 1,060 lb per sq in., 685 F 1—10,000-3,600 for 1,200 lb per sq in., 710 F 1—12,500-3,600 for 1,200 lb per sq in., 710 F				80,000-1800	50,000—h-p—3,600 l-p—1,800	6
No[l]				Yes	No	7
3 reheat boilers: For 1,150-lb boiler, reheater = 5,938; For two 1325-lb boilers, reheater = 6,936; For two 1325-lb boilers, reheater = 5,596				None	2 reheat boilers; steam reheater = 2,684; flue-gas reheater = 9,560	8
38,000-kw turbines—2 65,000-kw turbine—3				4 per turbine plus evaporator condenser	4 per turbine	9
From 38,000-kw turbines—240 From 65,000-kw turbine —310				357	425	10
8				4	2 reheat, 1 standard	11
3 boilers 365-715 19,743	1 boiler 1,150-700 15,631	2 boilers 1,325-725 15,093 + 1,206 waterwall	2 boilers 1,325-725 6,971 + 1,206 waterwall	36,792	10,699	12
11,100	11,100	5,596	9,634		Reheat boilers = 17,900 Standard boilers = 21,111	13
None	None	33,032	29,665	90,000	Reheat boilers = 51,606 Standard boilers = 46,915	14
150,000	142,000	225,000	250,000	560,000	500,000	15
83	83	86	86	87	No data	16
Refractory wall Taylor stoker	Refractory walls Taylor stoker	Refractory front wall and waterwalls	Refractory front wall and waterwalls	Bailey waterwalls 6 cross-tube burners per boiler	Bailey waterwalls, combination natural gas and mechanical fuel-oil burners	17
Double-roll, clinker grinders, ash hoppers and trucks	Double-roll, clinker grinder, ash hopper and trucks	Taylor stoker, double-roll, clinker grinder, ash hopper	Taylor stoker, double-roll, clinker grinder	Slag-tap A. S. H. sluicing	None	18
38,000-kw turbines—45,000 (each) 65,000-kw turbine—50,000			Ash hopper and trucks	45,000	34,000	19
68				75	63	20
32				32	50	21
628,075,000				299,327,300	102,257,000[o]	22
41,325,922				22,070,600	23,106,109[o]	23
586,749,078				277,256,700	78,150,891[o]	24
6.58				7.37	23.57[o]	25
$4.851				$3.10	Gas and oil used	26
14,083				13,185	Gas—1,180 Btu per cu ft Oil—18,500 Btu per lb	27
14,069[h]				15,080	19,700[o]	28
53.8				20.9	15.6[o]	29
23.1				21.3	11.7[o]	30

[g] The figures given under these items are for the entire plant including both the old l-p (220-lb) section and the new rebuilt section.
[i] Corrected for steam used for heating feedwater in l-p (225-lb) section of station.
[j] Relay capacity supplied by less efficient station and by interconnection with another utility.
[h] This station is the first 1200-lb superposed station. It was originally planned for 365-lb operation and at present operates at low capacity factor in parallel with neighboring hydroelectric system. The stand-by fuel plus operation of low-pressure boilers influence performance.
[l] To extent of capacity of largest unit on line.
[m] Not operated in 1935.
[n] This station carries peak loads with base load supplied by hydroelectric power from Niagara Falls.
[o] This station is a stand-by to a large hydroelectric system.

LOAD DISTRIBUTION
for Best Overall Economy

By E. D. ST. JOHN

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The author describes a system for determining mathematically the most efficient loading of turbines, boilers and generating stations, based on the theory that the most economical distribution of load occurs where the rate of change in total input to the units is the same.

IN POWER plant operation where two or more power generating units are operated in parallel there is the problem of determining the load to be carried on each unit for the most efficient overall economy. This is true whether the units be turbines, boilers or generating stations. The following solution of this problem is based on the theory that the most economical distribution between two or more units is where the rate of change in total input to the units is the same.

An analysis of the total energy curve will reveal that it is made up of three distinct parts: First, a function which has no relation to the load and is constant regardless of the amount of load on the unit. Second, a function which is directly proportional to the load. Third, a function which varies directly as the square of the load. In the diagram Fig. 1, each of these is shown, greatly exaggerated to bring out the respective parts. In this diagram the load on the unit is denoted by x and the total energy per hour input by Y; "a" corresponds to the energy consumed in overcoming losses such as frictional resistance which is a constant; bx corresponds to the directly proportional increase in energy consumed with increase in load; and cx^2 corresponds to the increment in energy necessary to overcome losses, such as the I^2R loss in the generator. Consequently, the total energy curve can be expressed by the quadratic equation,

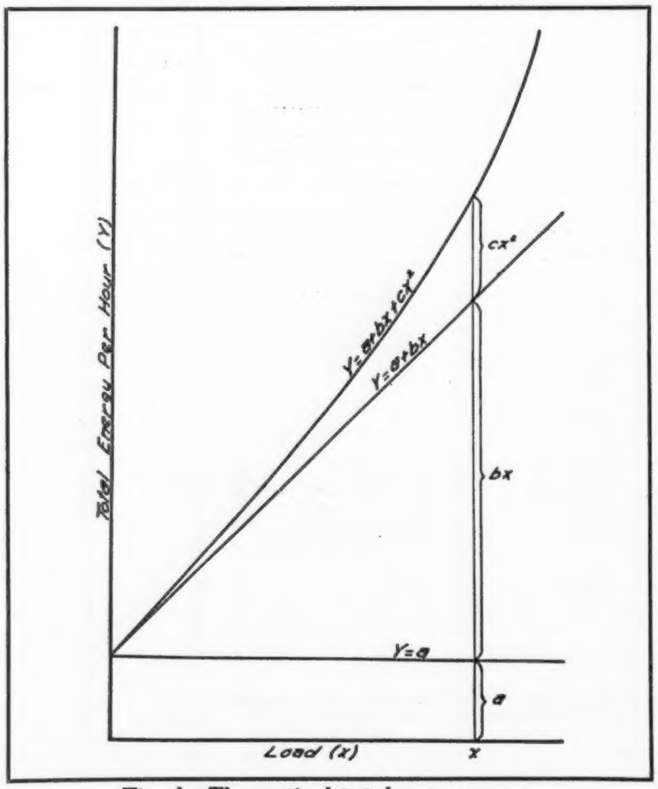


Fig. 1—Theoretical total energy curve

$$Y = a + bx + cx^2 \tag{1}$$

Before applying this method of load distribution proof will be made of the above statement that the most economical division of load on two or more units is at a point where the rate of change in total input is the same. In order to do this two hypothetical turbines will be considered and the equation for the total heat curve of turbine No. 1 will be expressed by $Y_1 = a_1 + b_1x_1 + c_1x_1^2$, and the equation for the total heat curve for turbine No. 2 by $Y_2 = a_2 + b_2x_2 + c_2x_2^2$; where Y_1 and Y_2 are the respective total heat inputs per hour, and x_1 and x_2 are the respective loads on the units. The total load on both machines, which throughout the immediate discussion is considered constant, will be represented by K. Then, $x_1 + x_2 = K$. The total heat used by both units per hour is

$$Y_1 + Y_2 = a_1 + b_1x_1 + c_1x_1^2 + a_2 + b_2x_2 + c_2x_2^2 \tag{2}$$

In order to get this equation in terms of x_1, substitute for x_2 its value, $K - x_1$, then

$$Y_1 + Y_2 = a_1 \times b_1x_1 + c_1x_1^2 + a_2 + b_2(K - x_1) + c_2(K - x_1)^2 \tag{3}$$

With the most economical distribution of load, $Y_1 + Y_2$ will be a minimum, therefore, the slope of the tangent at the minimum point of the curve represented by equation (3) will be equal to zero.

Differentiating equation (3) with respect to x_1 will give the slope of the tangent, then equating to zero,

$$\frac{dy}{dx_1} = b_1 + 2c_1x_1 - b_2 - 2c_2K + 2c_2x_1 = 0 \tag{4}$$

or

$$b_1 + 2c_1x_1 - b_2 - 2c_2\,(K - x_1) = 0 \tag{5}$$

Since $K - x_1 = x_2$

$$b_1 + 2c_1x_1 - b_2 - 2c_2x_2 = 0 \tag{6}$$

or $$b_1 + 2c_1x_1 = b_2 + 2c_2x_2 \qquad (7)$$

It will be noted that the first member of equation (7) is the first derivative of the equation for turbine No. 1, and the second member is the first derivative of the equation for turbine No. 2. The first derivative of these equations expresses the rate of change in total heat input. Therefore, the most economical distribution of load is where the rate of change in the total heat curves is the same. Since K does not appear in the last equation, the relation holds good for any load.

In order to apply this method of load distribution it is necessary to obtain sufficient basic data either from tests or guarantees, corrected to average operating conditions, for plotting total energy curves. Care should be taken in securing these data since a small error may greatly affect the results.

After plotting the total energy curves, values of Y may be read for any value of x and substituted in the basic equation $Y = a + bx + cx^2$. Since there are three unknowns in this equation it is necessary to obtain at least three values of Y. These values are generally taken at approximately one-half, three-quarters and full loads. If equations for more than three loads are used, in order to solve for the unknowns it is necessary to use the "method of least squares" which greatly complicates the calculations and for ordinary purposes is not necessary.

Turbine Load Distribution

In distributing the load between turbines in a station, it is recommended that the total energy curves be based on the total net heat used by the turbine and jet rather than the water rate. The heat returned to the system in the condensate should be deducted. This gives the machine the benefit of any heat recovery equipment it may have. For example, the distribution of load in a station of 26,000-kw capacity consisting of three units will be considered. Turbine No. 1 is a 6000-kw unit and Nos. 2 and 3 have capacities of 10,000 kw each.

Tests were made on each of these units at approximately one-half, three-quarters and full load. These test data were corrected to the average operating conditions relative to steam temperature, pressure and back pressure. As a rule, the steam temperature and pressure conditions vary only slightly over a year's period. However, if the characteristics of the condensers are such that a change in circulating water temperature does not have the same degree of effect on each unit it may be advisable to correct the back pressure for three operating seasons; one season being based on the average circulating-water temperature during the winter months, the second on the average temperature during the fall and spring months and the third on the average temperature during the summer months.

The average back pressure for these seasons may be readily obtained by first plotting the constant load back pressure curves for approximately one-half, three-quarters and full load similar to those shown in Fig. 2. The data for these curves and the average circulating water temperature for the three seasons were obtained from daily log sheets. After determining the average temperature for the three seasons, the back pressure for the three loads at the average season temperatures may be read from the constant load curves. This gives sufficient points to plot the constant temperatrue back pressure curves which are also shown in Fig. 2.

A separate loading schedule may then be worked out for each season, but this is not necessary for units in which the resulting change in back pressure due to change in circulating water temperature are similar. This can be determined by comparing the constant temperature back pressure curves of the various units. If approximately the same variation in back pressure is noted the loading schedule may be based on the mean or average condition.

In calculating the rate of change in total heat, the values of Y are read from the total heat curves as shown in Fig. 3. Using turbine No. 3 for an example, the following values of Y are read from the curve, when

x = 5 M kw, Y = 78.15 million Btu
x = 7.5 M kw, Y = 111.75 million Btu
x = 10 M kw, Y = 150.80 million Btu

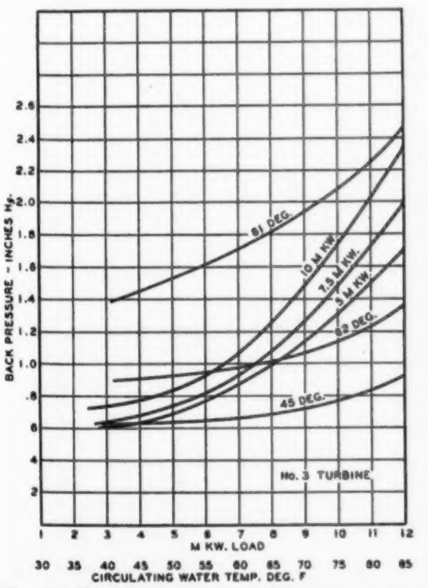


Fig. 2—Constant load and temperature back pressure curves

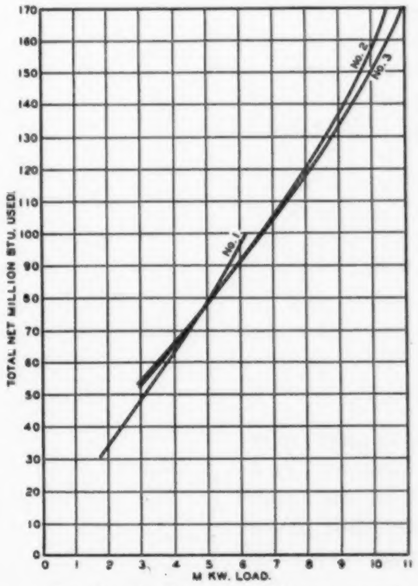


Fig. 3—Turbine total heat curves

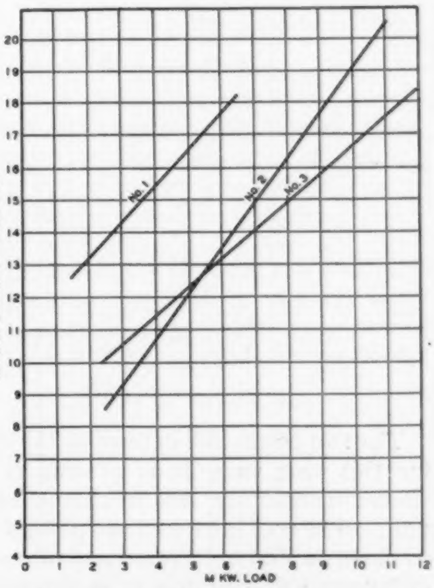


Fig. 4—Turbine rate of change curves

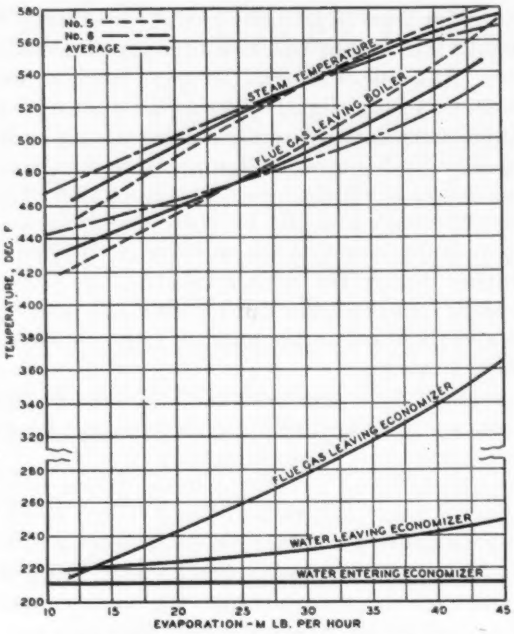


Fig. 5—Boiler performance curves

Substituting in the basic equation $Y = a + bx + cx^2$,

$$78.15 = a + 5b + 25c \quad \text{(I)}$$
$$111.75 = a + 7.5b + 56.25c \quad \text{(II)}$$
$$150.80 = a + 10b + 100c \quad \text{(III)}$$

Solving for values of a, b and c,

$$111.75 = a + 7.5b + 56.25c$$
$$78.15 = a + 5.0b + 25.00c$$
$$33.60 = 2.5b + 31.25c \quad \text{(IV)}$$

$$150.80 = a + 10.0b + 100.00c$$
$$111.75 = a + 7.5b + 56.25c$$
$$39.05 = 2.5b + 43.75c$$
$$33.60 = 2.5b + 31.25c$$
$$5.45 = 12.50c$$

$c = 0.436$

Substituting c in (IV)

$$33.60 = 2.5b + 13.625$$
$$b = 7.99$$

Substituting c and b in (I)

$$78.15 = a + 39.95 + 10.90$$
$$a = 27.3$$

Substituting these values in the derivative of the original equation,

$$\frac{dy}{dx} = bx + 2cx$$

$$\text{where } x = 5 \text{ M kw}, \frac{dy}{dx} = 7.99 + 2 \times 0.436 \times 5 = 12.35$$

$$\text{where } x = 10 \text{ M kw}, \frac{dy}{dx} = 7.99 + 2 \times 0.436 \times 10 = 16.71$$

The two points will determine the rate of change curve for this unit since it is a straight line curve. In a similar manner the rate of change curves for the other units are determined, and are plotted on the same graph as shown in Fig. 4. From these rate of change curves the distribution of load may be determined.

For example, to determine the correct distribution of 16 M kw load on the station, the rate of change at which the sum of the loads on the individual turbines will equal 16 M kw is found by observation. Reading up the rate of change scale it is found at 14, the rate of change intersects with the curve for No. 1 unit at 2.7 M kw, No. 2 unit at 6.4 M kw and No. 3 unit at 6.9 M kw. The sum of these loads equals the load on the station. In the same manner distribution for other loads may be determined and a schedule, as shown in Table I, may be prepared which shows proper load distribution for all combinations of units. By furnishing this schedule to the plant operators they will be able to distribute the load on the station for any combination of machines in service.

The number and combinations of machines in service will depend on the load and other operating conditions of the system; however, it is evident that the most efficient unit in a plant should be operated as much as conditions will permit and machines added to provide additional capacity in order of their efficiencies.

Boiler Load Distribution

When applying this method to boiler load distribution, x represents pounds of steam per hour output and Y represents the total Btu of fuel input. However, in a generating station the total heat curve of the boilers should be based on the equivalent boiler efficiencies rather than the actual boiler efficiencies. The equivalent efficiencies are the actual boiler efficiencies corrected so as to take into consideration the effect of variation in superheat on the efficiency of the turbines. This loads the boilers in such a manner as to obtain maximum over-

Table I

Turbine Loading Schedule

Station Load M kw	Turbines in Operation								
	1	2	1	3	2	3	1	2	3
7.5	1.8	5.7	1.8	5.7	4.2	3.3			
8.0	2.1	5.9	2.0	6.0	4.3	3.7			
8.5	2.4	6.1	2.2	6.3	4.5	4.0			
9.0	2.7	6.3	2.4	6.6	4.7	4.3			
9.5	3.0	6.5	2.6	6.9	4.9	4.6			
10.0	3.2	6.8	2.8	7.2	5.1	4.9			
10.5	3.5	7.0	3.1	7.4	5.3	5.2			
11.0	3.8	7.2	3.3	7.7	5.5	5.5			
11.5	4.0	7.5	3.5	8.0	5.7	5.8			
12.0	4.3	7.7	3.7	8.3	5.9	6.1			
12.5	4.6	7.9	4.0	8.5	6.1	6.4			
13.0	4.9	8.1	4.2	8.8	6.3	6.7	1.7	5.6	5.7
13.5	5.2	8.3	4.4	9.1	6.5	7.0	1.9	5.7	5.9
14.0	5.5	8.5	4.6	9.4	6.7	7.3	2.1	5.8	6.1
14.5	5.7	8.8	4.8	9.7	6.8	7.7	2.2	6.0	6.3
15.0	6.0	9.0	5.1	9.9	7.0	8.0	2.4	6.1	6.5
15.5	6.0	9.5	5.5	10.0	7.2	8.3	2.5	6.3	6.7
16.0	6.0	10.0	6.0	10.0	7.4	8.6	2.7	6.4	6.9
16.5					7.6	8.9	2.9	6.5	7.1
17.0					7.8	9.2	3.0	6.7	7.3
17.5					8.0	9.5	3.2	6.8	7.5
18.0					8.2	9.8	3.4	6.9	7.7
18.5					8.5	10.0	3.5	7.0	8.0
19.0					9.0	10.0	3.7	7.1	8.2
19.5					9.5	10.0	3.8	7.3	8.4
20.0					10.0	10.0	4.0	7.4	8.6
20.5							4.2	7.5	8.8
21.0							4.3	7.7	9.0
21.5							4.5	7.8	9.2
22.0							4.7	7.9	9.4
22.5							4.8	8.0	9.7
23.0							5.0	8.2	9.8
23.5							5.2	8.3	10.0
24.0							5.5	8.5	10.0
24.5							5.7	8.8	10.0
25.0							6.0	9.0	10.0
25.5							6.0	9.5	10.0
26.0							6.0	10.0	10.0

all station efficiency instead of maximum boiler plant efficiency.

Sufficient data should be obtained for the purpose of calculating a heat balance for each boiler, or group of boilers. From these heat balances the actual boiler efficiencies are determined. These efficiencies are corrected to the equivalent efficiencies which puts all the boilers on the same basis regardless of any variation in steam temperature between the boilers, due to different ratings or superheater capacities.

In order to calculate the equivalent efficiencies it is necessary first to determine the base heat in a pound of steam. This base heat is the Btu added per pound for average operating conditions of steam temperature, pressure and feedwater inlet temperature. The equivalent boiler efficiencies may then be calculated by using the following formula:

$$E_e = \frac{E_a H_b}{(1 \pm x)H_a}$$

where,

E_a = Actual boiler efficiency
H_b = Base heat added per pound of steam
H_a = Actual heat added per pound of steam
x = per cent change in turbine water rate due to superheat other than base superheat conditions
(Plus, if actual superheat is below base conditions; minus, if actual superheat is above base conditions).

To illustrate the boiler load distribution, the boilers in the 26,000-kw plant previously considered will be used. This plant consists of eight boilers; No. 1, 2, 3, 4, 5 and 6 are 5680-sq ft triple longitudinal-drum boilers having a maximum capacity of 45,000 lb of steam per hour, and No. 7 and 8 are 11,860-sq ft cross-drum boilers having a maximum capacity of 100,000 lb of steam per hour. Nos. 3 and 4, 5 and 6 are equipped with an economizer for each pair of boilers, and No. 7 and 8 each have an economizer. Each group of boilers has different superheater ratings.

Table II

Boiler Loading Schedule

M Kw Load	Approx. M Lbs. Steam per Hr.	Load to carry on each Boiler, M lbs. Boilers in Service: 1-A	1-B	1-A	2-B	1-A	3-B	1-A	4-B	1-A	4-B	1-C	1-A	4-B	2-C
4	60	45	15												
5	75	55	20	45	15										
6	90	66	24	52	19	45	15								
7	105	76	29	61	22	52	18	45	15						
8	120	88	32	70	25	60	20	52	17						
9	135	98	37	79	28	66	23	55	20						
10	150			86	32	72	26	62	22						
11	165			95	35	78	29	69	24						
12	180			100	40	84	32	72	27						
13	195			100	47	93	34	79	29						
14	210					99	37	86	31						
15	225					100	42	89	34	87	32	10			
16	240							96	36	92	34	12	88	33	10
17	255							100	38	98	36	13	93	35	11
18	270							100	42	100	39	13	98	37	12
19	285									100	43	13	100	40	13
20	300									100	45	20	100	43	14
21	315												100	45	18
22	330												100	45	25
23	345												100	45	33
24	360												100	45	40
		2-A	1-B	2-A	2-B	2-A	3-B	2-A	4-B	2-A	4-B	1-C	2-A	3-B	2-C
7	105	45	15												
8	120	51	18	44	16										
9	135	57	20	50	18	44	16								
10	150	63	24	55	20	49	17	45	15						
11	165	69	27	61	22	54	19	49	17						
12	180	76	28	66	24	59	21	53	19						
13	195	82	31	71	26	64	23	57	20						
14	210	89	32	77	28	69	24	61	22						
15	225	95	35	82	30	74	26	65	24						
16	240	100	40	88	43	78	28	70	25						
17	255			93	34	83	30	74	27						
18	270			98	37	88	31	78	29						
19	285			100	43	92	34	82	30						
20	300					96	36	86	32						
21	315					100	38	90	34	87	33	10	94	35	11
22	330							95	36	91	34	11	97	37	12
23	345							99	37	95	36	12	100	40	13
24	360							100	40	100	37	12	100	43	15
25	375									100	40	14	100	45	20
26	390									100	44	14	100	45	28

A - Boilers are the 11,860 sq.ft. boilers
B - Boilers are the 5,680 sq.ft. boilers equipped with economizers.
C - Boilers are the 5,680 sq.ft. boilers not equipped with economizers.
The most economical operating range of A boilers is from 70,000 to 95,000 lbs. per hr, for B boilers from 25,000 to 30,000 lbs. per hour, and for C boilers from 10,000 to 25,000 lbs. per hour.

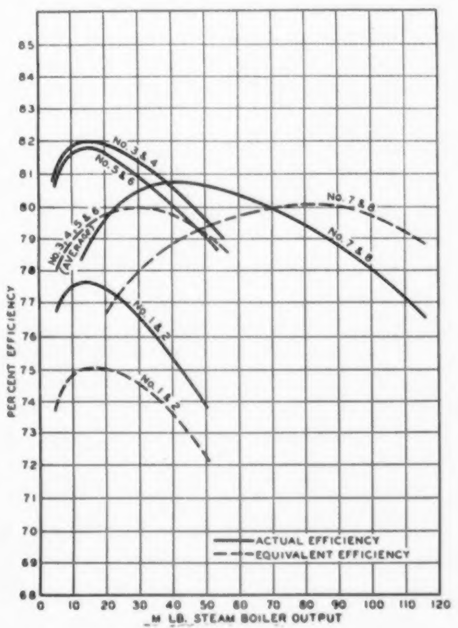


Fig. 6—Boiler efficiency curves

Typical data for heat balance calculation for boilers 5 and 6 are shown in Fig. 5. Since boilers 5 and 6 are identical and operate on the same economizer, the average temperatures were used for determining the actual and equivalent boiler efficiencies. The efficiency curves for all boilers are shown in Fig. 6. The equivalent efficiencies for boilers 3 and 4, 5 and 6 are practically the same, the average for these boilers is shown.

The total heat curve of a boiler is determined by taking several boiler outputs at equal intervals and multiplying by the base heat added per pound, then dividing by the corresponding equivalent efficiency. The total heat curves for each group of boilers are shown in Fig. 7. The total heat inputs for three different loads are read from these curves and substituted in the basic equation $Y = a + bx + cx^2$.

Using boilers 7 and 8 for an example, the following values of Y are determined from the curve, when

x = 40 M lb of steam, Y = 56.27 M Btu
x = 70 M lb of steam, Y = 97.11 M Btu
x = 100 M lb of steam, Y = 139.02 M Btu

Therefore,

$$56.27 = a + 40b + 1600c$$
$$97.11 = a + 70b + 4900c$$
$$139.02 = a + 100b + 10{,}000c$$

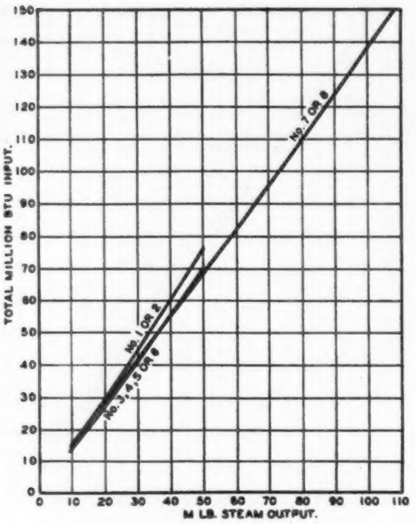


Fig. 7—Boiler total heat curves

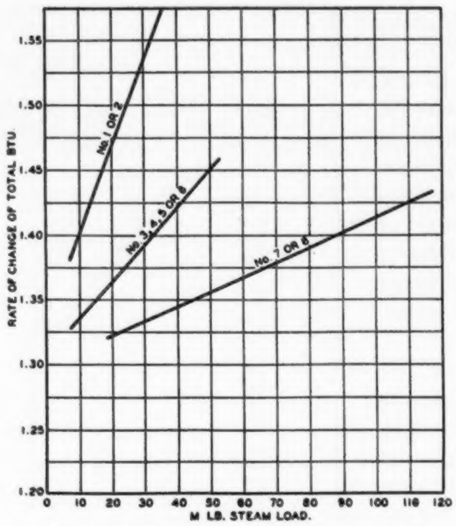


Fig. 8—Boiler rate of change curves

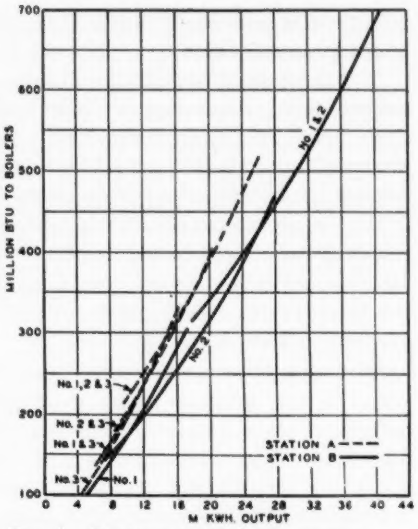


Fig. 9—Station total heat curves

Solving simultaneously for b and c,

$$b = 12.95$$
$$c = 0.0596$$

Substituting in the derivative of the basic equation,

$$\frac{dY}{dx} = b + 2cx$$

where

$$x = 50 \text{ M lb of steam}, \frac{dY}{dx} = 1.355$$

where,

$$x = 100 \text{ M lb of steam}, \frac{dY}{dx} = 1.414$$

The rate of change curves for the other groups of boilers are determined in a similar manner and are shown plotted in Fig. 8. From these rate of change curves the boiler loading schedule, as shown in Table II, was prepared in the same manner as the turbine loading schedule. By using this schedule the fireman is able to distribute properly the load between boilers for any load on the station. The boilers with the highest equivalent efficiencies should be given preference in operation, and the point of bringing on and taking off boilers determined so that the boilers in service at any time will be operating near their maximum equivalent efficiencies.

Station Load Distribution

On systems where two or more generating stations are interconnected with transmission lines this method of load distribution may be used to divide the load between the stations.

Station heat balances should be calculated for three or more loads on all combination of machines that are likely to be in service. In calculating the heat balances the load is distributed between the turbines according to the turbine loading schedule, and the required amount of steam is distributed between the boilers according to the boiler loading schedule. The million Btu input to each of the boilers is then determined from the boiler total heat curves, Fig. 7. The sum of these Btu inputs equals the total Btu input to the station, or the Btu required from fuel. Unless the stations have the same delivered fuel cost it is necessary to base the distribution on rate of change in total dollars per hour instead of Btu.

The total dollars per hour is based on the station output rather than the generation. Generally, the load on

Table III

Station Loading Schedule

System Load	Turbines in Operation															
M Kw	3A	2B	2,3A	1B	1,2,3A	1B	1,3A	2B	2,3A	2B	1,2,3A	2B	2,3A	1,2B	1,2,3A	1,2B
25	5.5	19.5	10.0	15.0	13.5	11.5										
26	5.5	20.5	11.0	15.0	14.0	12.0										
27	6.0	21.0	12.0	15.0	14.5	12.5										
28	6.0	22.0	13.0	15.0	15.0	13.0										
29	6.5	22.5	14.0	15.0	15.5	13.5										
30	6.5	23.5	15.0	15.0	16.0	14.0	7.5	22.5								
31	7.0	24.0	16.0	15.0	16.5	14.5	8.0	23.0	10.0	21.0						
32	7.0	25.0	17.0	15.0	17.0	15.0	8.5	23.5	10.5	21.5						
33	8.0	25.0	18.0	15.0	18.0	15.0	9.0	24.0	10.5	22.5						
34	9.0	25.0	19.0	15.0	19.0	15.0	9.5	24.5	11.0	23.0	13.0	21.0				
35	10.0	25.0	20.0	15.0	20.0	15.0	10.0	25.0	11.5	23.5	13.5	21.5				
36					21.0	15.0	11.0	25.0	12.0	24.0	14.0	22.0				
37					22.0	15.0	12.0	25.0	12.5	24.5	14.0	23.0	10.0	27.0		
38					23.0	15.0	13.0	25.0	13.0	25.0	14.5	23.5	10.5	27.5		
39					24.0	15.0	14.0	25.0	14.0	25.0	15.0	24.0	11.0	28.0	13.0	26.0
40					25.0	15.0	15.0	25.0	15.0	25.0	15.5	24.5	11.5	28.5	13.0	27.0
41					26.0	15.0	16.0	25.0	16.0	25.0	16.0	25.0	12.0	29.0	13.5	27.5
42									17.0	25.0	17.0	25.0	12.5	29.5	14.0	28.0
43									18.0	25.0	18.0	25.0	13.0	30.0	14.5	28.5
44									19.0	25.0	19.0	25.0	13.5	30.5	15.0	29.0
45									20.0	25.0	20.0	25.0	14.0	31.0	15.5	29.5
46											21.0	25.0	14.5	31.5	16.0	30.0
47											22.0	25.0	15.0	32.0	16.5	30.5
48											23.0	25.0	15.0	33.0	17.0	31.0
49											24.0	25.0	15.5	33.5	17.5	31.5
50											25.0	25.0	16.0	34.0	17.5	32.5
51											26.0	25.0	16.5	34.5	18.0	33.0
52													17.0	35.0	18.5	33.5
53													17.5	35.5	19.0	34.0
54													18.0	36.0	19.5	34.5
55													18.5	36.5	20.0	35.0
56													19.0	37.0	20.5	35.5
57													19.5	37.5	21.0	36.0
58													19.5	38.5	21.5	36.5
59													20.0	39.0	21.5	37.5
60													20.0	40.0	22.0	38.0
61															22.5	38.5
62															23.0	39.0
63															23.5	39.5
64															24.0	40.0
65															25.0	40.0
66															26.0	40.0

the station is controlled by the generator meters. Therefore, it is necessary to take into consideration the power used for station uses in determining this cost.

The station total heat curves for the 26,000-kw plant designated as Station A, are shown in Fig. 9. This station is a gas-burning plant, interconnected with a 40,000-kw coal-burning plant. The total heat curves for the latter, designated as Station B, are also shown in Fig. 9.

For example, in determining total cost of generation, 18,000-kw load on Station A with Nos. 1, 2 and 3 turbines in service will be considered. The station use under these conditions is 2.75 per cent, resulting in a plant output of 17,500 kw or 97.25 per cent of the generation. Reading the Btu input to the boilers at this output from the curve in Fig. 9, and multiplying by the station fuel cost, then dividing by 0.9725, gives the total cost in dollars per hour based on the output at 18,000-kw generation. This value is then used for Y in substituting in the basic equation. The rate of change in dollars per hour is calculated in the same manner as the rate of change in Btu for the turbines.

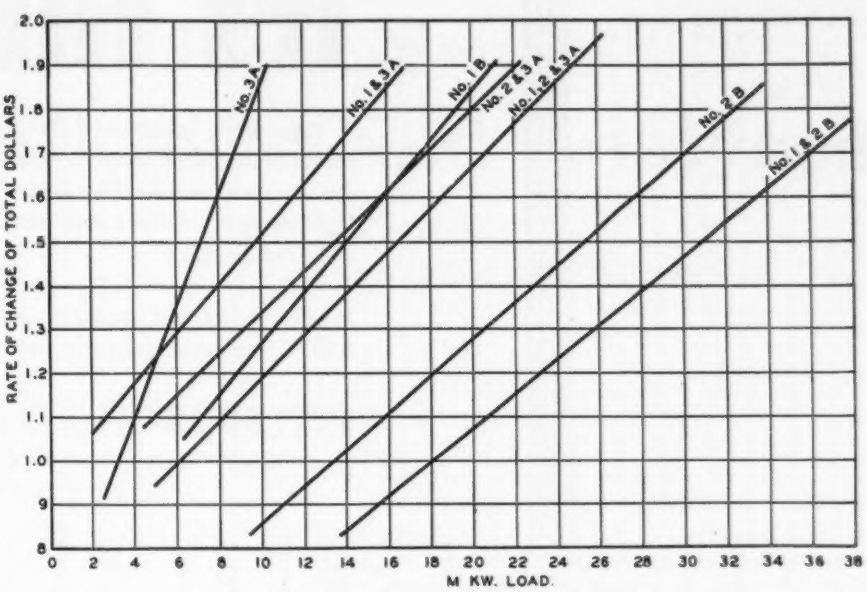


Fig. 10—Station rate of change curves

The rate of change curves for the various combinations of turbines in the two stations are shown in Fig. 10. From these curves, station loading schedules are prepared as shown in Table III. With the aid of these schedules the system operator can distribute the load between the stations for the most economical system operation.

Comments

This method of load distribution has been used for several years, and it has always been found to give the most economical results, providing the original data are correct. This can easily be checked by obtaining the sum of total inputs from the curves, with the load distributed according to schedule and comparing this input with that obtained when the load is shifted slightly off schedule. The input with the load distributed according to schedule will be the minimum.

The data necessary for the preparation of loading schedules are very useful for other purposes, such as checking operation and estimating fuel cost. It is interesting to note that the most economical point of unit loading may be determined by obtaining the square root of a divided by c.

If the total energy curve to a unit is represented by the equation $Y = a + bx + cx^2$, where Y equals the total energy per hour input and x equals the load, the equation for the heat rate curve may be obtained by dividing the above equation by x, thus

$$\frac{Y}{x} = \frac{a}{x} + b + cx$$

$\frac{Y}{x} = \frac{\text{Btu}}{\text{load}}$ which will be represented by z, then

$$z = \frac{a}{x} + b + cx$$

which is the equation for the variation in energy input per unit load with load.

Now the most economical load is at the lowest point in this curve, or where the slope of the tangent to the curve equals zero.

Differentiating this equation with respect to z will give the slope of the tangent,

$$\frac{dz}{dx} = -\frac{a}{x^2} + c$$

At the most economical point $\frac{dz}{dx} = 0$

therefore,

$$-\frac{a}{x^2} + c = 0$$

$$\frac{a}{x^2} = c$$

$$x^2 = \frac{a}{c}$$

$$x = \sqrt{\frac{a}{c}}$$

Therefore, if it is desirable to know the most efficient operating point of a generating unit, it may be determined by obtaining the square root of a divided by c.

In actual application of any method of load distribution there are always several factors necessary to take into consideration, such as banking losses, voltage correction and load protection. The effect of conditions such as these would have to be determined for each particular system.

O. H. Woolford, formerly manager of the Flow Meter Division, has been made Executive Officer of the General Sales Department of Cochrane Corporation, Philadelphia. Sales activities of the various divisions of the Company, which manufactures water conditioning equipment for power plants, steam specialties, flow meters and ice and material breaking equipment, will be coordinated under the newly created office. Mr. Woolford has been associated with Cochrane for the past ten years.

TENNESSEE COALS—
Their Classification and Analyses

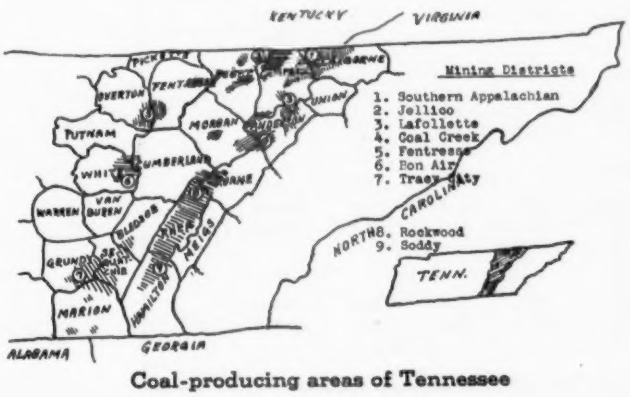
By P. B. PLACE
Combustion Engineering Company, Inc.

Previous articles of this series have dealt with Ohio, Kentucky, Virginia, Illinois, Indiana and Pennsylvania bituminous coals. In each case, as in the present article, the individual seams are traced through various counties, the coals are identified by county and trade names and their characteristics and analyses are given. Knowing the source of a Tennessee coal, its moisture and ash content, a complete analysis may be set up from the values given in the tables which will be sufficiently accurate for most power plant purposes.

TENNESSEE contributes but a small percentage of the bituminous coal production of the United States. At present the state is thirteenth in order of production with an annual output of between three and five million tons. The coal enjoys a ready market as industrial, railroad and domestic fuel.

The coal-bearing area is a narrow strip less than a hundred miles wide, extending diagonally across the middle of the eastern half of the state as shown in Fig. 1. This area is part of the Appalachian region and extends northward into eastern Kentucky and southward into Alabama. The total area underlain with coal covers some four thousand square miles and involves about twenty counties but the bulk of the production comes from three counties, Campbell, Claiborne and Anderson. Table I gives the relative production of the principal counties in recent years.

A number of centers of mining activity in the state are designated as mining districts. The names of these districts together with the counties involved are given in Table II and their location indicated in Fig. 1. Some of the districts have alternate names as given by different authorities and the Southern Appalachian and Jellico districts are continuations of the same districts in southeastern Kentucky.



Coal-producing areas of Tennessee

The mining districts may be grouped into two main fields. The northern or northeastern field includes the

TABLE I
RELATIVE PRODUCTION
IN
PRINCIPAL PRODUCING COUNTIES

County	1930	1931	1932
Campbell	24.4	23.0	23.3
Claiborne	16.0	20.3	18.6
Anderson	16.8	15.4	18.3
Morgan	6.8	8.0	8.6
Marion			7.0
Fentresse			3.4
	64.0	66.7	79.2

TABLE II
MINING DISTRICTS IN TENNESSEE
AND
COUNTIES INVOLVED

1. Southern Appalachian or Clear Fork District
   Campbell and Claiborne Counties
2. Jellico District
   Campbell and Scott Counties
3. La Follette or Caryville District
   Campbell and Anderson Counties
4. Coal Creek District
   Anderson and Morgan Counties
5. Fentresse or Crawford-Wilder District
   Fentresse and Overton Counties
6. Bon Air District
   White County
7. Tracy City District
   Marion, Grundy, Sequatchie and Bledsoe Counties
8. Walden Ridge District
   Rockwood District
   Roane and Cumberland Counties
   Soddy District
   Hamilton and Rhea Counties

Southern Appalachian or Clear Fork district, the Jellico district, the La Follette or Caryville district and the Coal Creek district. The principal coals mined in this field are the Coal Creek, Blue Gem, Jellico, Dean, Mingo, Red Ash and Rex seams. The southern or Cumberland Plateau field includes the Fentresse or Crawford-Wilder, Bon Air, Tracy City and Walden Ridge districts. The Walden Ridge district is divided by some authorities into the Rockwood and Soddy districts. The principal coals mined in this field are the Bon Air, Sewanee, Soddy, Wilder, Nelson and White Oak seams. As indicated in

TABLE III

TYPICAL INDIVIDUAL ANALYSES
OF
TENNESSEE COALS

As Received		Moisture and Ash Free							
Moisture	Ash	Volatile Matter	Fixed Carbon	Sulphur	Hydrogen	Carbon	Nitrogen	Oxygen	Btu per lb
				1. Campbell County					
Blue Gem Bed									
4.6	2.1	40.7	59.3	1.3	5.6	83.1	2.2	7.8	14880
3.5	2.1	42.1	57.9	1.1	5.7	83.3	2.1	7.8	15010
4.6	2.1	41.7	58.3	1.0	5.8	82.5	2.1	8.6	14770
4.4	1.9	40.5	59.5	0.9	5.7	82.9	2.3	8.2	14820
Jellico Bed									
4.1	2.2	41.2	58.8	0.8	5.8	83.1	2.2	8.1	14920
4.7	3.2	40.0	60.0	1.5	5.7	82.9	2.2	7.7	14840
3.2	5.9	41.3	58.7	2.0	5.7	82.8	2.2	7.3	14830
3.5	5.4	40.7	59.3	0.9	5.6	83.5	2.0	8.0	14890
Coal Creek Bed									
2.3	4.2	39.2	60.8	1.0	5.6	84.7	2.0	6.7	15170
3.3	6.8	37.3	62.7	1.3	5.2	84.5	1.9	7.1	15040
2.1	3.8	38.9	61.1	0.8	5.6	84.8	2.0	6.8	15240
2.0	4.1	40.1	59.9	1.3	5.6	84.4	2.1	6.6	15090
Red Ash Bed									
3.7	5.6	41.9	58.1	1.1	5.6	83.2	1.9	8.2	14890
3.5	6.0	42.7	57.3	1.3	5.7	83.9	1.9	7.2	14820
3.5	5.8	42.4	57.6	1.1	5.7	82.7	1.9	8.6	14860
3.4	5.8	42.3	57.7	1.3	5.7	83.0	2.0	8.0	14860
				2. Claiborne County					
Jellico Bed									
3.7	2.9	39.1	60.9	1.0	5.4	83.7	2.1	7.8	14960
3.0	3.9	39.9	60.1	1.3	5.6	84.3	2.1	6.7	15070
2.9	3.2	40.2	59.8	1.0	5.6	84.3	2.1	7.0	15090
Mingo Bed									
3.6	4.8	40.8	59.2	1.5	5.7	83.3	1.8	7.7	14950
3.9	4.6	40.0	60.0	1.3	5.7	83.5	2.0	7.5	14960
3.1	4.5	40.2	59.8	1.5	5.7	83.6	2.2	7.0	15010
				3. Anderson County					
Coal Creek Bed									
1.8	6.3	39.7	60.3	1.1	5.8	84.9	2.1	6.1	15140
1.8	5.1	39.3	60.7	1.4	5.6	84.8	2.1	6.1	15250
1.5	9.2	40.2	59.8	1.2	5.7	84.0	2.1	7.0	15240
Jellico Bed									
2.7	5.0	40.0	60.0	2.9	5.5	83.0	2.0	6.6	14930
4.0	8.4	39.9	60.1	2.3	5.4	83.3	2.0	7.0	14850
2.9	7.9	39.3	60.7	2.5	5.5	83.1	2.1	6.8	14830
				4. Morgan County					
Coal Creek Bed									
1.9	8.1	42.8	57.2	4.5	6.0	83.6	2.0	3.9	15390
1.5	9.6	45.0	55.0	6.1	5.7	81.9	1.9	4.4	15220
2.0	7.9	41.7	58.3	4.5	5.8	83.2	1.9	4.6	15330
Jellico Bed									
2.5	9.3	39.7	60.3	4.1	5.5	82.7	1.9	5.8	14910
2.3	7.3	40.2	59.8	2.8	5.7	83.4	2.1	6.0	15090
2.3	8.1	40.6	59.4	2.9	5.7	83.6	2.1	5.7	15160
				5. Marion County					
Sewanee Bed									
3.1	10.3	34.2	65.8	2.6	5.3	85.4	1.6	5.1	15140
3.4	8.3	31.9	68.1	0.9	5.3	86.6	1.7	5.5	15210
				6. Fentresse County					
Bon Air Bed									
2.8	9.7	42.1	57.9	3.4	5.9	83.0	1.6	6.1	15090
3.6	10.1	40.5	59.5	3.9	5.2	81.8	1.6	7.5	14840
				7. Grundy County					
Sewanee Bed									
2.9	11.0	34.5	65.5	1.3	5.2	85.1	1.8	6.6	15090
4.2	8.3	33.0	67.0	0.8	5.1	85.8	1.7	6.6	15040
				8. Hamilton County					
Soddy Bed									
2.7	6.2	32.8	67.2	0.8	5.5	87.2	1.4	5.1	15390
3.4	10.1	31.3	68.7	1.0	5.5	87.5	1.6	4.4	15420
				9. Overton County					
Wilder Bed									
2.8	10.8	40.8	59.2	3.4	5.4	82.4	1.6	7.2	14850
3.0	8.5	39.8	60.2	2.8	5.3	83.1	1.6	7.2	14900
				10. Scott County					
Glen Mary Bed									
3.9	6.6	40.7	59.3	2.5	5.6	83.1	2.0	6.8	14960
4.3	3.4	38.0	62.0	1.0	5.5	83.1	2.1	7.9	14980

TABLE IV
AVERAGE ANALYSES OF TENNESSEE COALS
FROM
PRINCIPAL DISTRICTS AND COUNTIES

As Received				Moisture and Ash Free					
Moisture	Ash	Volatile Matter	Fixed Carbon	Sulphur	Hydrogen	Carbon	Nitrogen	Oxygen	Btu per lb
Southern Appalachian or Clear Fork District									
1. Campbell County									
Coal Creek, Glen Mary Bed									
2-3	4-7	38.9	61.1	1.1	5.5	84.6	2.0	6.8	15135
Dean, Windrock Bed									
3-4	3-4	40.4	59.6	0.8	5.5	83.9	1.7	8.1	14950
Blue Gem, Rich Mountain Bed									
3-6	2-5	41.6	58.4	1.2	5.7	83.0	2.1	8.0	14850
Red Ash Bed									
3-4	5-6	42.4	57.6	1.2	5.7	83.2	1.9	8.0	14860
Jordan Bed									
3-5	3-4	40.0	60.0	1.0	5.5	83.4	2.1	8.0	14800
2. Claiborne County									
Mingo, Jack Rock Bed									
3-5	3-6	40.6	59.4	1.4	5.7	83.5	2.0	7.4	14990
Jellico Bed									
3-4	2-4	39.9	60.1	1.1	5.5	84.1	2.1	7.2	15050
Poplar Lick Bed									
2-4	6-10	41.6	58.4	2.7	5.9	83.1	2.0	7.3	14880
Average for Southern Appalachian District									
2-6	2-10	40.7	59.3	1.3	5.6	83.6	2.0	7.5	14940
Jellico District									
1. Campbell County									
Blue Gem, Rich Mountain Bed									
3-6	2-5	41.6	58.4	1.3	5.7	83.0	2.2	7.8	14850
Jellico, Log Mountain, Splint, State Bed									
3-6	2-9	40.3	59.7	1.4	5.5	83.2	2.0	7.9	14760
2. Scott County									
Blue Gem, Rich Mountain Bed									
3-5	6-8	39.7	60.3	2.1	5.5	82.5	1.9	7.0	14860
Jellico, State Bed									
2-4	4-6	39.3	60.7	2.1	5.6	83.5	2.1	6.7	15020
Coal Creek									
1-5	3-9	40.5	59.5	2.9	5.6	83.1	1.9	6.5	15020
Average for Jellico District									
1-6	2-9	40.3	59.7	1.9	5.6	83.1	2.0	7.4	14900
La Follette or Caryville District									
1. Campbell County									
Coal Creek Bed									
2-3	4-7	38.9	61.1	1.1	5.5	84.6	2.0	6.8	15135
Dean Bed									
3-4	3-4	40.4	59.6	0.8	5.5	83.9	1.7	8.1	14950
Rex Bed									
2-3	3-8	38.3	61.7	1.3	5.4	83.4	2.0	7.9	14990
2. Anderson County									
Coal Creek Bed									
1-3	5-10	39.6	60.4	1.3	5.6	84.9	2.1	6.1	15230
Dean Bed									
2-4	4-6	39.5	60.5	1.0	5.5	83.5	2.1	7.9	14860
Average for LaFollette District									
1-4	3-10	39.3	60.7	1.1	5.5	84.1	2.0	7.3	15070
Coal Creek District									
1. Anderson County									
Jellico Bed									
2-4	5-9	39.2	60.8	2.6	5.4	83.2	2.0	6.8	14870
Coal Creek Bed									
1-3	5-10	39.6	60.4	1.3	5.6	84.9	2.1	6.1	15230
Dean Bed									
2-4	4-6	39.5	60.5	1.0	5.5	83.5	2.1	7.9	14860

TABLE IV (Continued)

2. Morgan County									
Jellico Bed									
2-3	5-10	40.2	59.8	3.2	5.7	83.4	2.0	5.7	15015
Coal Creek Bed									
1-2	8-10	43.5	56.5	5.0	5.8	83.0	2.0	4.2	15320
Average for Coal Creek District									
1-4	4-10	40.7	59.3	2.8	5.6	83.5	2.0	6.1	15070
Fentresse or Crawford-Wilder District									
1. Fentresse County									
Bon Air Bed									
2-4	8-10	41.6	58.4	3.6	5.7	82.6	1.6	6.5	15010
White Oak Bed									
5-7	4-6	37.5	62.5	0.4	5.2	84.8	1.4	8.2	14850
Wilder Bed									
1-3	10-12	41.3	58.7	3.7	5.5	82.7	1.6	6.5	14910
2. Overton County									
Bon Air bed									
2-5	10-13	41.4	58.6	4.5	5.6	82.4	1.6	5.9	14950
Wilder Bed									
2-4	8-11	39.9	60.1	3.3	5.3	82.7	1.6	7.1	14870
Average for Fentresse District									
1-7	4-13	40.3	59.7	3.2	5.5	83.0	1.6	6.7	14915
Bon Air District									
1. White County									
Bon Air Bed									
2-4	7-11	44.3	55.7	3.9	5.7	82.7	1.5	6.2	15050
Sewanee Bed									
3-4	10-12	42.9	57.1	5.0	5.7	82.7	1.6	4.9	15150
Average for Bon Air District									
2-4	7-12	43.6	56.4	4.4	5.7	82.8	1.6	5.5	15100
Tracy City District									
1. Marion County									
Sewanee Bed									
3-4	8-10	33.0	67.0	1.7	5.3	86.0	1.6	5.4	15175
2. Grundy County									
Sewanee Bed									
2-4	7-11	33.8	66.2	1.3	5.2	85.5	1.7	6.3	15075
3. Sequatchie County									
Sewanee Bed									
2-3	8-10	33.8	66.2	1.5	5.3	86.4	1.7	5.1	15290
4. Bledsoe County									
Sewanee Bed									
2-4	7-9	33.6	66.4	1.2	5.4	86.4	1.6	5.4	15280
Average for Tracy City District									
2-4	7-11	33.5	66.5	1.4	5.3	86.1	1.6	5.6	15200
Rockwood District									
1. Roane County									
Sewanee Bed									
2-4	9-15	33.8	66.2	1.0	5.3	86.7	1.5	5.5	15285
Rockwood, Soddy Bed									
4-6	7-9	36.9	63.1	0.6	5.2	84.3	1.6	8.3	14820
2. Cumberland County									
Sewanee Bed									
2-3	7-10	30.3	69.7	0.8	4.9	86.6	1.6	6.1	15230
Nelson Bed									
2-3	6-8	35.1	64.9	0.7	5.3	87.0	1.5	5.5	15390
Average for Rockwood District									
2-6	6-15	34.0	66.0	0.8	5.2	86.1	1.6	6.3	15150
Soddy District									
1. Rhea County									
Sewanee Bed									
2-4	10-12	35.4	64.6	1.5	5.4	85.6	1.6	5.9	15210
Richland, Soddy Bed									
2-3	11-15	34.5	65.5	1.6	5.4	85.8	1.6	5.6	15255
2. Hamilton County									
Soddy Bed									
2-4	6-10	32.1	67.9	1.0	5.5	87.4	1.5	4.6	15420
Average for Soddy District									
2-4	6-15	34.0	66.0	1.4	5.4	86.3	1.6	5.3	15295

Table I, the bulk of the production of the state comes from the northern field.

A large number of coal beds have been found in the state but correlation of the seams in various counties and adjacent states is not complete and many of the seams have alternate names. Thus, the Blue Gem seam is also known as Rich Mountain, the Coal Creek as Glen Mary, the Dean as Windrock and the Jellico as Log Mountain, Splint or State. Similarly, the Mingo is known as Jack Rock and the Soddy as Richland or Rockwood. These and other alternate names are usually local designations of the main seam and sometimes only tentative correlations of seams in different localities and indicative of the confusing variety in nomenclature and the need for standardization in this and many other states.

Geologically, Tennessee coals belong to the Pennsylvania series of the Carboniferous age. The coal-bearing formations in the state have been classified as the Anderson (top), Scott, Wartburg, Briceville and Lee corresponding in general to the Harlan, Wise, Gladeville, Norton and Lee formations of Kentucky and Virginia. Most of the coals mined in the state come from the Lee formation.

Physically, Tennessee coals are coking bituminous coals with a hard and blocky structure. They stand transportation well, are excellent domestic fuel and are also employed for general industrial use and as railroad fuel. They have low moisture, are generally low in ash and sulphur, have high volatile content and a heat value of about 15,000 Btu per lb on a moisture and ash-free basis. The northern coals have a higher volatile content than the southern coals. Ash-fusion temperatures are generally medium, between 2250 and 2550 F although both high- and low-fusion coals are found.

The coals may be burned on underfeed stokers. They may also be burned in pulverized form but, like eastern Kentucky coals, they are harder to grind than most high volatile coals of Pennsylvania and West Virginia. Some are suitable for by-product coking and for pottery burning. Because of the low-moisture and low-ash content and general structure, the Blue Gem, Jellico and Coal Creek coals make desirable domestic furnace coals.

Typical individual analyses of the various coals in the principal producing counties are given in Table III. As in previous articles of this series on coal, the moisture and ash values of the analyses are on an "as received" basis and other values are "moisture- and ash-free." The general range of variation in analytical values is shown in Table III. The counties are arranged in order of their importance on a production basis and only the principal beds are given.

Table IV gives average analyses for the principal beds mined in the counties of the mining districts. Knowing the source of a Tennessee coal and its moisture and ash content, a complete analysis may be set up for the coal from these average analyses that will be sufficiently accurate for most engineering purposes. Inspection of the averages for the different districts in Table IV shows that a general classification from an analysis standpoint, divides Tennessee coals into two groups, those from the northern districts and those from the southern districts.

In the absence of specific information, the two analyses given in Table V may be used as representative of Tennessee coals. Moisture and ash values have been assumed for the purpose of presenting the analyses on "as received" and dry basis. Whether a coal in question is a northern or southern coal can probably be established, but if not, the northern analysis is probably more applicable to the average run of Tennessee coals since the bulk of the production is from the northern districts.

TABLE V
AVERAGE ANALYSES FOR TENNESSEE COALS

	Northern Districts *			Southern Districts **		
	As Received	Dry	Moisture and Ash Free	As Received	Dry	Moisture and Ash Free
Moisture	2.5	-	-	3.0	-	-
Ash	5.0	5.13	-	8.0	8.25	-
Volatile Matter	37.46	38.42	40.5	30.26	31.20	34.0
Fixed Carbon	55.04	56.45	59.5	58.74	60.55	66.0
	100.00	100.00	100.0	100.00	100.00	100.0
Sulphur	1.85	1.90	2.0	1.07	1.10	1.2
Hydrogen	5.18	5.31	5.6	4.72	4.86	5.3
Carbon	77.15	79.12	83.4	76.72	79.09	86.2
Nitrogen	1.76	1.80	1.9	1.42	1.47	1.6
Oxygen	6.56	6.74	7.1	5.07	5.23	5.7
	92.50	94.87	100.0	89.00	91.75	100.0
Btu per pound	13875	14230	15000	13530	13945	15200

* Southern Appalachian
Jellico
La Follette
Coal Creek
Fentresse
Bon Air

** Tracy City
Walden Ridge
Rockwood
Soddy

The New York Power Show

Present indications point to the Twelfth National Exposition of Power and Mechanical Engineering as fully reflecting present activity in the field and equalling the high marks set by its predecessors of pre-depression years. From reservations already made it is expected that there will be about three hundred exhibitors and space is now being sold on the third floor of the exposition building. In contrast to the show of 1934, this year will again see many manufacturers of heavy equipment represented, in addition to those making auxiliaries and accessories. While information at this early date is scant as to features of the equipment that will be shown, it is anticipated that the exhibits will reveal many new developments.

The Show is scheduled to take place November 30 to December 5 at the Grand Central Palace, New York, and, as in former years, will run concurrently with the Annual Meeting of the A.S.M.E. and the A.S.R.E.

Newer Methods of SULPHATE DETERMINATIONS and Their Application to Plant Control

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As pointed out by the author, certain well-known methods of analyzing feed and boiler waters are not well suited to plant control unless the plant has laboratory facilities with personnel trained in making chemical analyses. Therefore, two comparatively recent methods—the turbidimetric and the "THQ" methods offer considerable promise because of their simplicity and applicability without requiring laboratory facilities. These methods are described.

MANY of the great strides which have been made in the advancement of water conditioning in recent years, have been predicated, to a very large extent, upon similar strides in methods of chemical analysis of both feedwater and boiler salines. The establishment of proper chemical balances and their maintenance is, in turn, dependent upon frequent plant control analyses.

It is hardly expected that analyses of this character could be made with the dependability of a regular laboratory analysis, for in many instances it is practically impossible to build laboratories adjacent to the boiler room. Furthermore, any control tests must be simple enough that they may be performed, and the results understood, by the average boiler-room operator. Such an operator is rarely trained in laboratory procedure, and tests made must be such that no great amount of the operator's time will be occupied in their performance. Because of the simplicity necessary in such analyses and by virtue of the conditions under which they must be made, it becomes essential that volumetric or nephelometric methods be used just as much as possible. Gravimetric methods can hardly be tolerated for the reason that they require greater time, together with the services of a laboratory balance, which in itself is a very delicate instrument, subject to inaccuracies in the presence of vibration. They, therefore, cannot lend themselves to proper use in many boiler rooms or large power plants, particularly in plants where large turbines or other prime movers are in use.

Heretofore, these requirements have been met in practically all essential determinations excepting in the analysis of sulphates. It has long been known that the determination of the sulphate ion has been a matter of considerable importance, but little has been done on this for the reason that the best known method, until recent times, has been of a gravimetric type, wholly dependent upon the use of a laboratory balance.

The determination of the sulphate ion is of considerable importance to maintain recommended sulphate-carbonate ratios for the inhibition of caustic embrittlement, as prescribed by The American Society of Mechanical Engineers, and further gives very important data from which can be ascertained whether calcium sulphate is being kept in solution or is being deposited in the form of scale by comparison with a salt which remains soluble, such as chlorides.

The most accurate known method for the determination of sulphates is the precipitation of the sulphate ion by barium chloride, filtering, igniting and weighing the precipitate in the form of barium sulphate. This method is described in detail in practically any textbook on quantitative analysis. It is long and tedious and requires the use of a laboratory balance. While this method is subject to some slight error, due to the adsorption in the precipitate of other salts, generally speaking it is free from serious error and has been adopted by The American Society for Testing Materials as the referee method. The method, however, because of the time element and the delicate laboratory balance required, does not lend itself for plant control work.

The Benzidine Method

The benzidine (sometimes referred to as the benzidine-hydrochloride) method was proposed some time ago and was the first to offer the principles of volumetric analysis to the determination of the sulphate ion. While somewhat shorter than the gravimetric method, it entailed quite a long procedure. The method consists mainly of the addition of a solution of benzidine hydrochloride to the unknown which precipitates sulphates as benzidine sulphate. The precipitate is washed after filtering and is then titrated with a standard solution of sodium hydroxide to the phenolphthalein end-point. The actual manipulation of the sample in this method of analysis is somewhat more involved than the above description seems, as it requires filtering, which in itself frequently becomes a time-consuming element. It is also recom-

mended that the titration with the sodium hydroxide solution be carried out hot to insure greater accuracies.

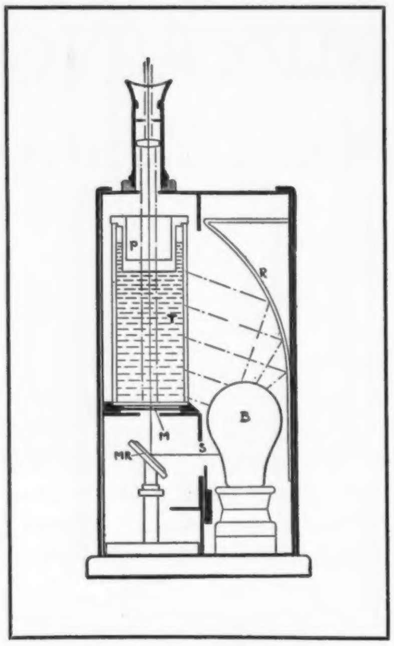

Fig. 1—Diagram of Turbidimeter

This, also, frequently is not very convenient in plant control operation. The method is subject to large errors in samples showing less than 50 ppm and is, therefore, not recommended in the analysis of boiler feedwaters. Above 50 ppm sulphates, the error does not appear greater than 10 per cent, provided extreme care is exercised in the analysis and considerable shaking is done during the titration of the sample.

Turbidimetric Methods

A turbidimetric method for the determination of the sulphate ion holds the best promise for a rapid analysis. Various methods of this type have been previously offered, which depend mostly upon the disappearance of a light filament when observed through the solution in which the sulphates have been precipitated by barium chloride. The observer looks through various depths or concentrations of the solution, until the light filament disappears and from the calibration of the instrument can ascertain the amount of sulphate present. Until a comparatively short time ago, an accuracy greater than 15 to 20 per cent could not be claimed (1); see bibliography.

The main factors contributing to such a large error were: 1, effect of various impurities; 2, effect of differences in barium chloride crystals; 3, effect of minor variations in temperature; 4, method of manipulation; and 5, observational errors. Due to a difference in eyesight, it was extremely difficult for two operators to check in their readings on many of the turbidimeters offered for sulphate determinations.

There has recently been offered a turbidimetric method for the determination of sulphates in water (2) (3) which has successfully solved the objections in the older turbidimetric methods. It is based on the use of a turbidimeter designed to use a Tyndall effect in lighting. A very high degree of accuracy is procurable in low concentrations of sulphates and is, therefore, applicable to determination of sulphates in feedwaters as well as boiler concentrates. This employs a turbidimeter as illustrated in Fig. 1. An opal glass bulb *B*, which has been carefully standardized, is mounted in a metal housing, with a large reflector *R* above and to the rear. A precision slit *S*, governing the amount of light permitted to strike the mirror with a circular milk glass reflector *MR* is operated by a graduated drum knob, not shown in the illustration. At the side of the apparatus to which the door is attached, is a mirrored platform *M* with a round blank space in the center. This platform holds the tubes *T* containing the solution under observation. The light rays emanating from the standard bulb, are reflected into the liquid column in the tube and by such side illumination of the suspended particles, the Tyndall effect is produced. Light rays also pass through the precision slit, and are reflected by the mirror upward through the solution directly into the occular on the top of the instrument.

These light rays will appear to the observer as a circular spot in the center of the Tyndall effect of the illuminated liquid which is seen lighter or darker than the Tyndall light (see Fig. 2) depending on the size of the opening of the slit. If more light is being admitted from the bottom than from the side, the circular spot will appear as in *A* Fig. 2. If more light is being admitted from the side than from the bottom, the circular spot will then appear as in *C*. When there is exactly the same amount of light from both the side and the bottom, the spot will entirely disappear as in *B*. By revolving the drum knob, the opening of the slit is so regulated as to obtain an equalization of the light and the subsequent disappearance of the spot.

The tubes used are made for liquid depths of 10 and 20 mm and are made of optical glass with fused-on plano-parallel bottom plates. The upper end of the tube is covered with a short glass plunger (*P*, Fig. 1) which automatically adjusts the proper depth of liquid. The same plunger is used with both the 10- and 20-mm tubes.

A B C

Fig. 2. Observation Fields

Center, balanced; left and right, unbalanced

Different ranges of turbidity can be covered by inserting standard filter plates designated as grey glass, milk glass and clear. Each instrument is carefully standardized and is supplied complete, with calibration curves.

This method has been carefully tested for sulphates ranging from 0.7 to 2044 ppm and has been found extremely accurate although accuracies are greater in the lower ranges, up to approximately 50 ppm. This is because of the fact that it is necessary to dilute more concentrated samples and with each dilution, a small error is multiplied according to the amount of the diluent. For this reason, this method has its greatest application in the analysis of raw and boiler feedwaters. It is very simple, accurate and quick and can be used by any op-

erator without previous training in chemical laboratory manipulation.

"THQ" Method

Another method for sulphate determination that has recently been developed, and which bids fair to become the most reliable for rapid work, is known as the "THQ" method. This employs the use of disodium tetrahydroxyquinone as an internal indicator in a direct titration method of analysis. It is entirely a volumetric method and has been adopted as an official optional method by both The American Society for Testing Materials and The American Water Works Association. It appears in the new (8th) edition of American Public Health Association Manual, "Standard Methods of Water Analysis," long considered as the official source of information in water analysis.

This method was first proposed by Schroeder (4) in 1933, at which time he reported on preliminary observations in this method of analysis. Further studies on this method recently appeared by Sheen and Kahler (5) who have greatly extended its value. In this paper, it is shown that sulphates can be determined by this method up to 30,000 ppm, which is equivalent to a 3 per cent solution of SO_4. Comparison with the turbidimetric method previously described and with the gravimetric method on boiler water and boiler feedwaters, shows that acceptable results in all concentrations were obtained. The method is the essence of simplicity itself. A sample of the water to be analyzed is measured by a pipette into an Erlenmeyer flask and an equal amount of ethyl or isopropyl alcohol is added. A measured quantity of the prepared "THQ" indicator is added, the flask twirled for a moment to dissolve it entirely and then titrated with a standardized barium chloride solution. The end-point is taken with a change of color from a yellow to an orange, very similar to the Methyl Orange end-point in alkalimetry titrations. Results obtained by this method, check gravimetric analyses within an average of 3 per cent. Phosphates, which Schroeder recognized as an interfering ion can be eliminated by a simple pH control. The method lends itself to plant control very admirably, requires no special apparatus and can be performed by any plant operator previously instructed in the rudimentary principles of an alkalinity determination, long accepted as a standard in plant control work.

With the introduction of these two new methods of determinations, sulphate ions can now be determined quickly and accurately by operators without special chemical training, and an entirely new aspect is now possible in plant control work in the establishment of chemical balances in boiler waters.

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Steam vs. Hydro Power in France

At the Washington meeting of the World Power Conference, E. Genissieu, a member of the French delegation presented three papers which gave some very interesting figures on the swing from steam to hydro power in France and revealed the financially vulnerable position of the government-supported hydro plants and the measures taken by the French Government to bolster them. According to the figures given, the total installed capacity of generating equipment in France is,

Steam stations	7,097,600 kw
Hydro stations	3,321,700 kw

The total amount of Government funds put into hydroelectric and related transmission lines is:

(a)	Fr 316,000,000—repayable loans and annuities
	50,000,000—subsidies on account of unemployment relief*
	366,000,000—Total
(b)	100,000,000—repayable loans**
(c)	12,000,000—advanced to hydro projects in which the state is a shareholder
(d)	180,000,000—invested in transmission network in liberated war regions
	Fr 650,000,000—Grand total

Mr. Genissieu's paper relates that with the advent of the depression all electric output was reduced and, in particular, industrial load was lost by hydro plants, further compromising their earning capacity. Although there were already substantial differentials favoring these partly government-owned hydro plants over steam plants which are all privately owned, further definite measures were taken to load the hydro stations at the expense of the steam stations. These measures were consummated by statutes passed in 1935 giving wide scope for ministerial decrees to deal with the economic situation. The paper ascribes much of the necessity for this to the need for conserving coal, and to the fiscal situation involving a restriction upon imported fuel.

Prior to the depression, and to the decrees of 1935, hydro and transmission projects received state loans and grants, at no interest or reduced interest; steam stations did not. The output of steam stations is subject to a two per cent excise tax; hydro stations are not. But it is particularly through the influence of the Government, and quite recently, that the displacement of production has reached such proportions that in 1935, for the first time, hydro production exceeded steam.

The total production of electric energy in 1934 was 15,172,400,000 kwhr, nearly equalling the maximum production of 1930 which was 15,339,300,000 kwhr. The relative proportions produced by steam and hydro, for the past ten years are as follows:

	Per Cent of Total[1]	
	Steam	Hydro
1926	57.9	42.1
1927	55.7	44.3
1928	56.8	43.2
1929	57.2	42.8
1930	55.2	44.8
1931	58.4	41.6
1932	57.7	43.3
1933	55.2	44.8
1934	52.6	47.4
1935	48.5	51.5
1st 3 mos of 1936 (est.)	(43.7) approx.	(56.3) approx.

* To fifteen hydro projects comprising 417,000-kw installed capacity and a total cost of 1,500,000,000 Fr—about 24 per cent of the total investment.
** To eight transmission projects comprising about 20 per cent of all transmission at the same voltage at a total cost of 350,000,000 Fr—about 28 per cent of the total cost.
[1] Same author—WPC Sec I, No. 1.

The thermal efficiency of steam stations in France is of a high order, particularly in the metropolitan district of Paris, which includes a substantial portion of all steam production. The average figures of coal per kilowatt-hour in these stations are as follows:

	Pounds of Coal per Kwhr[2]	
	Paris	Total France
1932	1.55	1.86
1933	1.38	1.71
1934	1.22	1.60
1935	1.21	1.60

An interesting result of the shift in sources of production is contained in data for energy lost in transmission, as follow:

	Per Cent Loss in Transmission Per Cent
1928	12.8
1929	13.8
1930	13.5
1931	13.8
1932	16.3
1933	17.1
1934	17.1

In amounts of energy the comparison for the two years 1930 and 1934, is as follows:

	Total Output All Sources	Output of Steam Stations Million Kilowatt-hours	Losses in Transmission
1930	15,339	8463	2139
1934	15,172	7977	2680
Difference		−486	+541

Increased transmission losses exceeded the reduction in steam station output by 55,000,000 kwhr.

[2] Same author—WPC, Sec I, No. 2.